IMPROVED MEASUREMENT PLACEMENT AND TOPOLOGY PROCESSING IN POWER SYSTEM STATE ESTIMATION

A Dissertation

by

YANG WU

Submitted to the Office of Graduate Studies of
Texas A&M University
in partial fulfillment of the requirements for the degree of

DOCTOR OF PHILOSOPHY

August 2007

Major Subject: Electrical Engineering

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Approved by:

Chair of Committee,	Mladen Kezunovic
Committee Members,	Chanan Singh
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	William Lively
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ABSTRACT

Improved Measurement Placement and Topology Processing in Power System State Estimation. (August 2007)

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Chair of Advisory Committee: Dr. Mladen Kezunovic

State estimation plays an important role in modern power system energy management systems. The network observability is a pre-requisite for the state estimation solution. Topological error in the network may cause the state estimation results to be seriously biased. This dissertation studies new schemes to improve the conventional state estimation in the above aspects.

A new algorithm for cost minimization in the measurement placement design is proposed in this dissertation. The new algorithm reduces the cost of measurement installation and retains the network observability. Two levels of measurement placement designs are obtained: the basic level design guarantees the whole network to be observable using only the voltage magnitude measurement and the branch power flow measurements. The advanced level design keeps the network observable under certain contingencies.

To preserve as many substation measurements as possible and maintain the network observability, an advanced network topology processor is introduced. A new method - the dynamic utilization of substation measurements (DUSM) - is presented. Instead of seeking the installation of new measurements in the system, this method dynamically calculates state estimation measurement values by applying the current law that regulates different measurement values implicitly. Its processing is at the substation level and, therefore, can be implemented independently in substations.

This dissertation also presents a new way to verify circuit breaker status and identify topological errors. The new method improves topological error detection using the method of DUSM. It can be seen that without modifying the state estimator, the status of a circuit breaker may still be verified even without direct power flow measurements. Inferred measurements, calculated by DUSM, are used to help decide the CB status.

To reduce future software code maintenance and to provide standard data exchanges, the newly developed functions were developed in Java, with XML format input/output support. The effectiveness and applicability of these functions are verified by various test cases.

To My Wife and Parents

ACKNOWLEDGMENTS

First of all, I would like to express my sincere gratitude to my advisor, Dr. Mladen Kezunovic, for his time, guidance and support. His great technical knowledge and experience contributed enormously to this dissertation.

In addition, I am also grateful to other members of my dissertation committee: Dr. Chanan Singh, Dr. Andrew K. Chan and Dr. William Lively, for their precious time and valuable comments.

I would also like to thank Dr. Tatjana Kostic from ABB Corporate Research for her valuable advices during my research activities; Dr. Markus Braendle, for his interest and contribution to the measurement placement algorithm; my colleagues Xu Luo, Nan Zhang, Hongbiao Song, Satish Natti, Peichao Zhang, Goran Latisko, Maja Knezev, Zarko Djekic and Anisha Jonas, for their help and encouragement in my research work.

Finally, I would like to thank my wife Xiaoyu Qu, for her constant love, care and support throughout my graduate study.

TABLE OF CONTENTS

CHAPTER Page

LIST OF TABLES

LIST OF FIGURES

FIGURE Page

FIGURE Page

CHAPTER I

INTRODUCTION

A. Power System Analysis

Power system is one of the most complex technical terrestrial systems in the world, which is composed of transmission, sub-transmission, distribution and generation subsystem. Transmission systems may contain large numbers of substations which are interconnected by transmission lines, transformers, and other devices used for system control and protection. Electric power is injected into the system by the generators and absorbed from the system by the loads at these substation. Distribution systems are typically outlined in a tree structure, where feeders stretch from distribution substations and branch out over a wide geographic area.

A power system is said to operate in a normal state if all loads can be supplied with power by generators without violating any operational constraints, such as the limits of transmission line power flows and bus voltage magnitudes. The system is called *secure* if it can remain in a normal state after a contingency (e.g., outage of generator or transmission line) occurs.

Power systems are operated by dispatchers from the control centers. The main task of the dispatchers is to maintain the system in the secure state. This requires continuous monitoring of the system. Existing substations are typically equipped with remote terminal units (RTUs) which collect different types of measurements from the field and transmit them to the control center using a supervisory control and data acquisition (SCADA) system. Fig. 1 shows the infrastructure of a typical SCADA system. The SCADA host computer at the control center receives measurements

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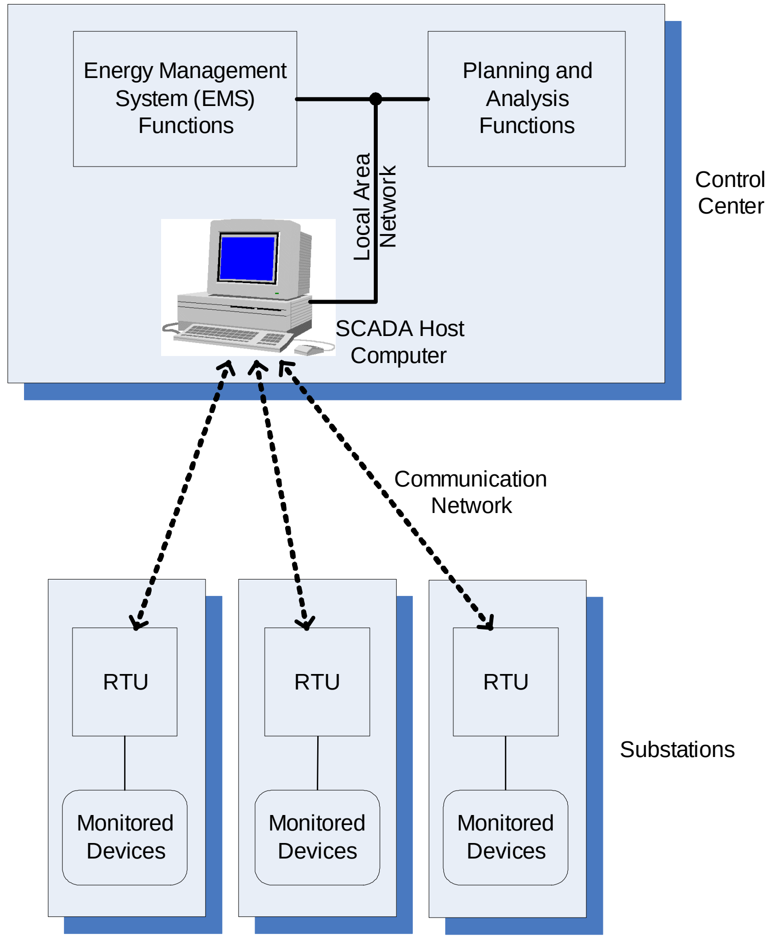

Fig. 1. Existing SCADA system configuration

from all the RTUs via one of many types of communication media such as microwave, telephone line, fiber optics, satellite, etc.

More recently, intelligent electronic devices (IEDs) are introduced to substations. In the future, they may replace or complement the existing RTUs [1] and may be linked to a SCADA front-end computer through a local area network (LAN). The SCADA host computer at the control center would be able to communicate with all the front-end computers to receive measurements. Fig. 2 shows a typical configuration of a future SCADA system.

As shown later in this dissertation, the introduction of IEDs and front-end com-

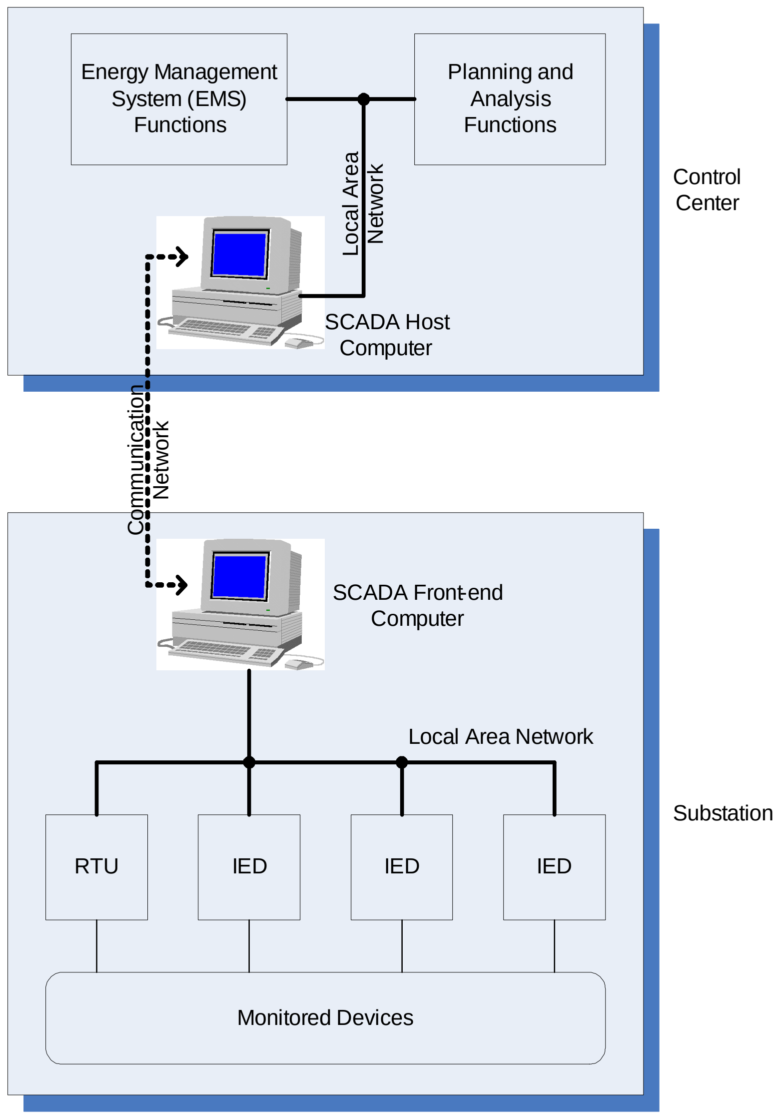

Fig. 2. Future SCADA system configuration

puter brings the possibility of many new applications to the energy management system (EMS). The research developments presented in this dissertation offer improvements for both existing and future SCADA infrastructures.

Measurements from all parts of the system are acquired and then processed in order to determine the system state, such as the bus voltages and transmission line power flows. Such a data processor is called a *state estimator* (SE). The solution of the state estimator will provide an optimal estimate of the system state based on the available measurements. This will provide inputs for other EMS application functions such as contingency analysis, automatic generation control, load forecasting, optimal power flow, etc.

Since its introduction in the late 1960s, the power system state estimator has become the core of the online security analysis function. Measurement configuration and its effect on state estimation have been addressed by the development of *observability analysis*, which determines whether a state estimation solution can be obtained under the current measurement configuration. To spot possible errors in measurement data, *bad data processing* has also been developed. Some other improvement efforts have been made to enhance state estimation, such as the network parameter estimation [2], robust state estimation [3], and the use of phasor measurement units (PMUs) in state estimation [4, 5].

B. Research Topics

The configuration of measurements and placement of RTUs are important factors for the performance of a state estimator. Placement design for required measurements and RTUs has been widely studied. It is formulated as an optimization problem, whose objective is to minimize the number of equipment or the installation cost for measurements while satisfying certain performance constraints [6]. One requirement for a successful execution of state estimation is that the network needs to be observable [7] [8]. Therefore, the foremost performance constraint is the network observability. The first research topic of this dissertation is how to minimize the cost of measurement devices while meeting the network observability constraints. This topic focuses on the improvements in designing SCADA systems that use existing infrastructure as shown in Fig. 1.

Conventional network topology processing (NTP) identifies energized, de-energized, and grounded electrical islands and is performed before state estimation and other related functions (observability analysis and bad data processing) are executed [7]. A complete description of the network model and the location of measurement devices in terms of bus-sections and switching devices is assumed to be available. The NTP transforms the bus-section/switching-device model into the bus-branch model and assigns metering devices to the components of the bus-branch model. Many measurement devices are not efficiently used in the bus-branch model during the processing of the NTP. On the other hand, in a situation that the network is not observable, previous research only proposes ways to decide where to add more measurements in the bus-branch model. It is this dissertation's interest to look into the possibility to enhance the conventional NTP and use those measurements that are available in substations but not represented in the bus-branch model. This topic applies to the future SCADA infrastructure where IEDs are available in substations.

In the NTP, state estimation assumes that the topology is correct and proceeds to estimate the states and identify analog bad data whenever redundancy allows it. However, when there is an error in the reported circuit breaker (CB) status, it usually causes the state estimate to be significantly biased. As a result, the bad data detection and identification routine may erroneously eliminate several analog measurements that appear as introducing bad data, finally yielding an unacceptable state. Traditional bad data detection techniques have trouble identifying the source of the problem, once such an error occurs. Many existing methods that handle topological errors introduce extra variables into the state estimator to estimate the status of CBs. This dissertation will look at this problem from another angle without changing the state estimator. Features of the enhanced NTP will be combined with rule-based analysis techniques to determine the power flows through CBs and CB status. This topic also relates to the future SCADA infrastructure.

C. Dissertation Outline

The dissertation is organized as follows. A background of power system state estimation is provided in Chapter II. Chapter III discusses the three areas that this dissertation focuses on, as well as the existing methods and their limitations. Chapters IV, V and VI talk about the new algorithms developed, namely, cost minimization in measurement placement, dynamic utilization of substation measurements and improved detection of topological errors respectively. Software implementation issues are covered in Chapter VII. Chapter VIII lists some test results to show the effectiveness of developed algorithms. Applicability in practice, including both benefits and concerns, is presented in Chapter IX. The conclusions are given in Chapter X. References related to proposed work and appendices including file formats and substation configuration layouts used for testing are enclosed at the end.

D. Summary

This chapter briefly introduces power systems operations and analysis in the areas of EMS. The history and future trend of SCADA and state estimation are presented.

Three research topics are introduced in Section B and will be further discussed in Chapter III. The outline of the dissertation is listed in Section C.

CHAPTER II

BACKGROUND

A. Introduction

This chapter discusses theoretical aspects of the topics covered in this dissertation.

An overview of the power system state estimation (SE) is introduced, followed by descriptions of the four major components of a state estimator: topology processing, observability analysis, state estimation and bad data detection.

B. Overview of Power System State Estimation

The power system state estimation was introduced by the late Fred Schweppe of MIT in 1969 [9]. Since then, it has played an essential role in modern Energy Management systems (EMS) [7, 10–12]. Power system state estimation provides an accurate and reliable data input for other key functions of the EMS system, such as security monitoring, optimal power flow, security analysis, online power flow studies, supervisory control, automatic voltage control and economic dispatch control [13, 14].

State estimation refers to the procedure of obtaining the voltage phasors at all of the system buses at a given point in time. This may be achieved in the future by having synchronized phasor measurements installed on all buses in the system. Today most of all bus voltages are not directly measured. State estimation procedure makes use of a set of redundant measurements in order to filter out such errors and find an optimal estimate of the state. Simultaneous measurement of quantities at different parts of the system is usually not achievable, hence a certain amount of time skew between measurements in commonly tolerated.

The objective of static state estimation is to estimate the complex bus voltage phasors (the states) at every bus in a given power system using the measurements of various line flows, bus injections, voltage and line current magnitudes as well as the information about the status of the circuit breakers, switches, transformer taps and the parameters of the transmission lines, transformers and shunt capacitors and reactors. State estimation process involves the following functions:

1. Topology preprocessing – obtains the one-line model of the system based on the information on the circuit breaker / switch statuses.

2. Observability analysis – tests whether or not the available measurements are sufficient to estimate the entire system state. If the test fails, then observable parts of the system will be identified and pseudo-measurements will be added to enlarge the observable islands.

3. State estimation – solves a nonlinear optimization problem whose solution yields the state estimate for the entire system. Once the state is estimated, estimates for all other quantities of interest such as the line flows, can be computed.

4. Bad data processing – checks the measurements for the existence of possible bad data. If any of the measurements are flagged as bad data, they will be removed or corrected so that the state estimate will not be biased.

Measurements can be of different types. Commonly used measurement types are briefly described below:

1. Flows – Real and reactive power flows measured at the terminal buses of a transmission line or transformer.

2. Injections – Real and reactive power net injections at system buses.

3. Voltage magnitude – At system buses.

C. Topology Processing

In this dissertation, the term *connectivity* refers to the static physical layout of devices (transmission lines, bus-bars, switches, etc.) in a power system network; the term *topology* refers to the dynamic structure of a network determined upon the status of switches and circuit breakers (CBs). Connectivity is usually fixed over longer periods of time while topology changes relatively frequently over time. The term *node* refers to an electrical node in the detailed substation model; the term *bus* refers to an electrical node in the bus-branch model after the processing of an NTP. A bus usually consists of one or several nodes that are connected by closed CBs or switches. Fig. 3 illustrates the meaning of these terms.

An NTP takes care of the first stage of data processing in a state estimation function. Its task is to determine the network topology (usually in the form of a bus-branch model) based on the detailed description of network connectivity and the real-time CB status [7, 15]. In a conventional NTP, the input data consist of two parts.

1. Description of the Physical Devices' Connectivity in the Network

The physical devices include generators, loads, CBs, transmission lines, transformers, current transformers (CTs), voltage transformers (VTs), etc. These devices can be grouped into four categories based on their characteristics that affect the determination of network topology:

1. CBs and other switching devices: these devices have two terminals - a from-node and a to-node. Their states are either open or closed. An open CB corresponds to an open circuit, or an infinite impedance branch; a closed CB corresponds to a short circuit, or a zero impedance branch.

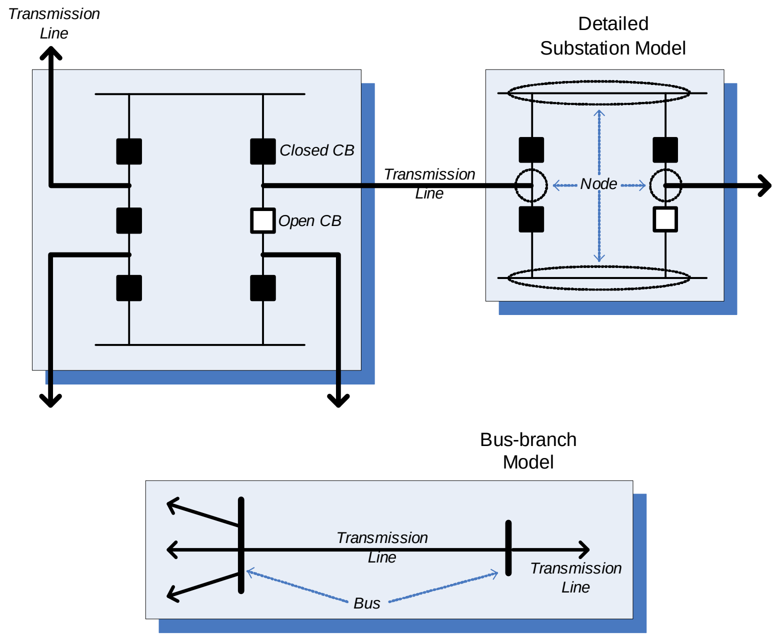

Fig. 3. Detailed substation model and bus-branch model

2. Nodal injection devices (generators, loads, etc): these devices have one terminal - the node that they are connected to.

3. Transmission lines, transformers: these devices are usually represented by non-zero impedance branches that have two terminals - a from-node and a to-node.

4. Measurements: the commonly used measurements include CB power flow measurements, nodal power flow injection measurements and voltage magnitude measurements.

2. CB Status and Analog Measurement Data

The CB status measurement data are provided to the NTP so that it can merge electrical nodes that are connected by closed CBs into a single bus. After that, the NTP also needs to assign the nodal injection devices and branches available in the detailed substation models to the proper locations in the bus-branch model. The analog measurement data, such as CB power flows, nodal injection power flows and voltage magnitudes also need to be provided to the NTP. These measurement data need to be processed before they can be used by a state estimator. Most state estimators that are available in power systems can deal with three types of measurements in the bus-branch network: bus voltage magnitude measurements, bus power flow injection measurements, and branch power flow measurements. Many of the analog measurement data gathered by the physical devices in the substations cannot be used directly in the state estimator since the values that they monitor do not fall in any of these three categories. These values could be combined and new meaningful measurement values could be calculated. The existing NTPs use the following principles in treating the raw analog measurement data:

1. A nodal voltage magnitude measurement is directly converted to a bus voltage magnitude measurement by mapping the node number to its corresponding bus number in the bus-branch model.

2. A nodal power flow injection measurement is converted to either a branch power flow measurement (if a branch is connected to the node and brings the injection) or a portion of a bus injection power flow measurement (if an injection device is connected to the node and brings the injection). If a bus is composed of several nodes in the detailed substation model, a bus injection measurement is created only if all nodal injection measurements are available.

3. The CB power flow measurements will be used to calculate the nodal injections, if possible. The calculated nodal injections will be further processed in the way described in 2.

An example of how NTP works is shown in Fig. 4. A substation that has nine CBs and eight nodes is shown in Fig. 4(a). Bus 9, 10 and 11 are from external substations.

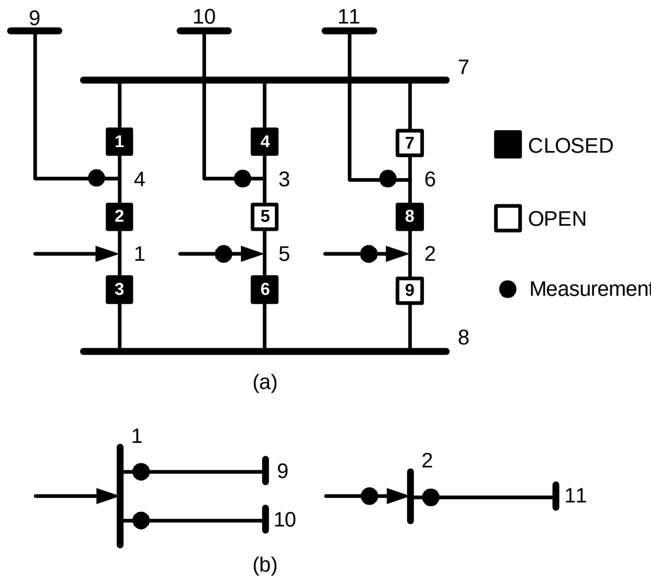

Fig. 4. An example of the detailed substation model and the used bus-branch model. (a) Detailed substation model. (b) Used bus-branch model.

Three injection devices are connected to node 1, 2 and 5. Power flow measurements are installed on three transmission lines, as well as node 2 and 5. Fig. 4(b) shows the used bus-branch model. It can be seen that two buses exist in this substation. Node 1, 3, 4, 5, 7 and 8 are merged into bus 1, and node 2 and 6 become bus 2. The three branch measurements are preserved in the bus-branch model. The nodal injection measurement at node 2 is also preserved. The nodal injection measurement at node 5, however, is eliminated since bus 1's injection equals to the sum of node 1 and 5's injections, and node 1's injection is unknown.

D. Observability Analysis

Various methods proposed for network observability analysis have been well documented in the literature [8, 16–20]. A brief introduction of the basic ideas of the observability analysis is shown below.

A linear, time-invariant (LTI) system is usually described in the following state space representation:

$$\dot{x}(t) = Ax(t) + Bu(t) \tag{2.1}$$

$$\dot{y}(t) = Cx(t) + Du(t) \tag{2.2}$$

where: x is the *state vector*;

y is the *output vector*;

u is the *input* (or *control*) *vector*;

A is the *state matrix*;

B is the *input matrix*;

C is the *output matrix*;

D is the *feedthrough* (or *feedforward*) *matrix*.

Methmetically, the necessary and sufficient condition for an LTI system to be observable is:

$$rank \begin{bmatrix} C \\ CA \\ CA^2 \\ \vdots \\ CA^{n-1} \end{bmatrix} = n \tag{2.3}$$

where $rank\ A$ means the maximum number of columns (or rows) of A which are linearly independent.

In power system state estimation, the state vector x of the system contains the voltage magnitude and phase angles of buses (or *nodes* in circuit theory). The output vector y (which is often denoted as z in power system analysis) contains the measurements, such as bus voltages, branch power flows and bus injection power flows. Since state estimation is a steady state function, the state vector is constant, and the state matrix and input matrix are both 0, i.e., $A = 0$ and $B = 0$. Also, measurements that are considered in power system state estimation have no feedthrough, i.e., $D = 0$. Thus the power system state estimation problem becomes:

$$z = Cx \tag{2.4}$$

However, different from the LTI system, the power system is a non-linear system. The output matrix C is a function of x, and (2.4) can be represented as:

$$z = f(x) \tag{2.5}$$

First-order Taylor approximation of (2.5) yields:

$$H \cdot \Delta x = z - f(x^0) = \Delta z \tag{2.6}$$

where:

$H = \frac{\partial f(x)}{\partial x}$, evaluated at some x^0;

$\Delta x = x - x^0$.

Equation (2.6) relates all existing measurements to the state variables, using the first-order Taylor approximation. An estimate for Δx can be obtained as long as the rank of H is equal to the dimension of Δx or x. Therefore, the observability in power system state estimation is defined as:

$$rank\ H = n \tag{2.7}$$

where n is the dimension of the state vector x.

It should be noted that the system observability is independent of the branch parameters as well as the operating state of the system. Therefore, all system branches can be assumed to have an impedance of $j1.0$ per unit (p.u.) and all bus voltages can be set equal to 1.0 p.u. for the purpose of observability analysis. It can be shown that in such a power system network, H can be calculated by:

$$H = M \cdot A^T \tag{2.8}$$

where:

M is the *measurement-branch incidence matrix*,

$$M_{ij} = \begin{cases} 1 & \text{If measurement } i \text{ is incident to bus } j \text{ at the "from end".} \\ -1 & \text{If measurement } i \text{ is incident to bus } j \text{ at the "to end".} \\ 0 & \text{If measurement } i \text{ is not incident to bus } j. \end{cases}$$

A is the *branch-bus incidence matrix*,

$$A_{ij} = \begin{cases} 1 & \text{If branch } i \text{ is incident to bus } j \text{ at the "from end".} \\ -1 & \text{If branch } i \text{ is incident to bus } j \text{ at the "to end".} \\ 0 & \text{If branch } i \text{ is not incident to bus } j. \end{cases}$$

The method that uses (2.7) and (2.8) to decide whether a network is observable is call the *numerical method*.

Observability analysis can also be carried out by using a *topological method*. If a tree can be formed such that each branch of this tree contains a power flow measurement, then the phase angles at all buses can be determined, i.e. the system will be fully observable. The available measurements should be assigned to the branches according to the following rules:

1. If the branch flow is measured, the branch is assigned to its flow measurement.

2. If an injection is measured at a terminal node of a branch, the branch can be assigned to that injection.

3. Once a branch is assigned to a measurement, it can not ba assigned to any other measurement.

The essential steps of the algorithm can be summarized as follows:

1. First assign all the flow measurements to their respective branches.

2. Then, try to assign the injection measurements in order to reduce the existing forest by merging existing trees.

Note that there is no way to predict the correct sequence for processing injections. Implementation of the method requires proper back-up and re-assignment of injections when necessary.

The network observability analysis determines if a state estimation solution for the entire system can be obtained using the available set of measurements, therefore it is a very important component in the EMS and it is usually carried out before the execution of state estimation.

E. WLS State Estimation

Various methods for state estimation have been introduced in the past decades [12, 21, 22]. Among those methods, Weighted Least Squares (WLS) algorithm is the most popular one. The objective function to be minimized is the weighted sum of squares of the measurement residuals.

1. Measurement Model

Consider the set of measurements given by the vector z:

$$z = \begin{bmatrix} z_1 \\ z_2 \\ \vdots \\ z_m \end{bmatrix} = \begin{bmatrix} h_1(x_1, x_2, \cdots, x_n) \\ h_2(x_1, x_2, \ldots, x_n) \\ \vdots \\ h_m(x_1, x_2, \cdots, x_n) \end{bmatrix} + \begin{bmatrix} f_1 \\ f_2 \\ \vdots \\ f_m \end{bmatrix} = h(x) + e \tag{2.9}$$

where:

$h^T = [h_1(x), h_2(x), \ldots, h_m(x)]$;

$h_i(x)$ is the nonlinear function relating measurement i to the state vector x;

$x^T = [x_1, x_2, \ldots, x_n]$ is the system state vector;

$e^T = [e_1, e_2, \ldots, e_m]$ is the vector of measurement errors.

The following assumptions are commonly made, regarding the statistical properties of the measurement errors [11]:

1. $E(e_i) = 0, i = 1, \ldots, m$.

2. Measurement errors are independent, i.e. $E[e_i e_j] = 0$.

   Hence, $Cov(e) = E[e \cdot e^T] = R = diag\{\sigma_1^2, \sigma_2^2, \cdots, \sigma_m^2\}$.

The standard deviation σ_i of each measurement i is calculated to reflect the expected accuracy of the corresponding meter used.

The WLS estimator will minimize the following objective function:

$$J(x) = \sum_{i=1}^{m} [z_i - h_i(x)]^2 / R_{ii} = [z - h(x)]^T \cdot R^{-1} \cdot [z - h(x)] \tag{2.10}$$

At the minimum, the first order optimality conditions will have to be satisfied. These can be expressed in compact form as follows:

$$g(x) = \frac{\partial J(x)}{\partial x} = -H^T(x) \cdot R^{-1} \cdot [z - h(x)] = 0 \tag{2.11}$$

where $H(x) = \frac{\partial h(x)}{\partial x}$.

The above nonlinear equation can be solved using the Newton iterative method as shown below:

$$x_{k+1} = x^k - \left[G(x^k)\right]^{-1} \cdot g(x^k) \tag{2.12}$$

where:

k is the iteration index;

x_k is the solution vector at iteration k;

$G(x_k) = \frac{\partial g(x_k)}{\partial x} = H^T(x_k) \cdot R^{-1} \cdot H(x_k)$;

$g(x_k) = -H^T(x_k) \cdot R^{-1} \cdot [z - h(x_k)]$.

$G(x)$ is called the *gain matrix.* It is sparse, positive definite and symmetric provided that the system is fully observable. The matrix $G(x)$ is typically not inverted, but instead it is decomposed into its triangular factors and the following sparse linear set of equations are solved using forward/back substitutions at each iteration k:

$$[G(x_k)]\,\Delta x_{k+1} = H^T(x^k) \cdot R^{-1} \cdot [z - h(x_k)] \tag{2.13}$$

where $\Delta x^{k+1} = x^{k+1} - x^k$.

The set of equations given by (2.13) is also referred to as the *Normal equations.*

2. The Measurement Jacobian

WLS State Estimation involves the iterative solution of the Normal equations given by Equation (2.13). An initial guess has to be made for the state vector x^0. As in the case of the power flow solution, this guess typically corresponds to the flat voltage profile, where all bus voltages are assumed to be 1.0 per unit and in phase with each others.

If three types of measurements – line power flows, bus power injections and bus voltage magnitudes – are taken into consideration, the structure of the measurement Jacobian H will be as follows:

$$H = \begin{bmatrix} \frac{\partial P_{inj}}{\partial \theta} & \frac{\partial P_{inj}}{\partial V} \\ \frac{\partial P_{flow}}{\partial \theta} & \frac{\partial P_{flow}}{\partial V} \\ \frac{\partial Q_{inj}}{\partial \theta} & \frac{\partial Q_{inj}}{\partial V} \\ \frac{\partial Q_{flow}}{\partial \theta} & \frac{\partial Q_{flow}}{\partial V} \\ 0 & \frac{\partial V_{mag}}{\partial V} \end{bmatrix} \tag{2.14}$$

The expressions for each partition are given below:

1. Elements corresponding to real power injection measurements:

$$\begin{aligned} \frac{\partial P_i}{\partial \theta_i} &= \sum_{j \in \aleph_i} V_i V_j (-G_{ij} \sin\theta_{ij} + B_{ij} \cos\theta_{ij}) - V_i^2 B_{ii} \\ \frac{\partial P_i}{\partial \theta_j} &= V_i V_j (G_{ij} \sin\theta_{ij} - B_{ij} \cos\theta_{ij}) \\ \frac{\partial P_i}{\partial V_i} &= \sum_{j \in \aleph_i} V_j (G_{ij} \cos\theta_{ij} + B_{ij} \sin\theta_{ij}) + V_i G_{ii} \\ \frac{\partial P_i}{\partial V_j} &= V_i (G_{ij} \cos\theta_{ij} + B_{ij} \sin\theta_{ij}) \end{aligned}$$

2. Elements corresponding to reactive power injection measurements:

$$\begin{aligned} \frac{\partial Q_i}{\partial \theta_i} &= \sum_{j \in \aleph_i} V_i V_j (G_{ij} \cos\theta_{ij} + B_{ij} \sin\theta_{ij}) - V_i^2 G_{ii} \\ \frac{\partial Q_i}{\partial \theta_j} &= V_i V_j (-G_{ij} \cos\theta_{ij} - B_{ij} \sin\theta_{ij}) \\ \frac{\partial Q_i}{\partial V_i} &= \sum_{j \in \aleph_i} V_j (G_{ij} \sin\theta_{ij} - B_{ij} \cos\theta_{ij}) - V_i B_{ii} \\ \frac{\partial Q_i}{\partial V_j} &= V_i (G_{ij} \sin\theta_{ij} - B_{ij} \cos\theta_{ij}) \end{aligned}$$

3. Elements corresponding to real power flow measurements:

$$\begin{aligned} \frac{\partial P_{ij}}{\partial \theta_i} &= V_i V_j (g_{ij} \sin\theta_{ij} - b_{ij} \cos\theta_{ij}) \\ \frac{\partial P_{ij}}{\partial \theta_j} &= -V_i V_j (g_{ij} \sin\theta_{ij} - b_{ij} \cos\theta_{ij}) \end{aligned}$$

$$\frac{\partial P_{ij}}{\partial V_i} = -V_j(g_{ij}\cos\theta_{ij} + b_{ij}\sin\theta_{ij}) + 2(g_{ij} + g_{si})V_i$$
$$\frac{\partial P_{ij}}{\partial V_j} = -V_i(g_{ij}\cos\theta_{ij} + b_{ij}\sin\theta_{ij})$$

4. Elements corresponding to reactive power flow measurements:

$$\frac{\partial Q_{ij}}{\partial \theta_i} = -V_iV_j(g_{ij}\cos\theta_{ij} + b_{ij}\sin\theta_{ij})$$
$$\frac{\partial Q_{ij}}{\partial \theta_j} = V_iV_j(g_{ij}\cos\theta_{ij} + b_{ij}\sin\theta_{ij})$$
$$\frac{\partial Q_{ij}}{\partial V_i} = -V_j(g_{ij}\sin\theta_{ij} - b_{ij}\cos\theta_{ij}) - 2(b_{ij} + b_{si})V_i$$
$$\frac{\partial Q_{ij}}{\partial V_j} = -V_i(g_{ij}\sin\theta_{ij} - b_{ij}\cos\theta_{ij})$$

5. Elements corresponding to voltage magnitude measurements:

$$\frac{\partial V_i}{\partial V_i} = 1,\ \frac{\partial V_i}{\partial V_j} = 0,\ \frac{\partial V_i}{\partial \theta_i} = 0,\ \frac{\partial V_i}{\partial \theta_j} = 0$$

where:

V_i, θ_i are the voltage magnitude and phase angle at bus i;

$\theta_{ij} = \theta_i - \theta_j$;

$G_{ij} + jB_{ij}$ is the ijth element of the complex bus admittance matrix;

$g_{ij} + jb_{ij}$ is the admittance of the series branch connecting buses i and j as shown in Fig. 5;

$g_{si} + jb_{si}$ is the admittance of the shunt branch connected at bus i as shown in Fig. 5;

$\aleph_i$ is the set of bus numbers that are directly connected to bus i.

3. Decoupled Formulation of the WLS State Estimation

The main computational burden associated with the WLS state estimation solution algorithm presented in section II.B.2 is the calculation and triangular decomposition

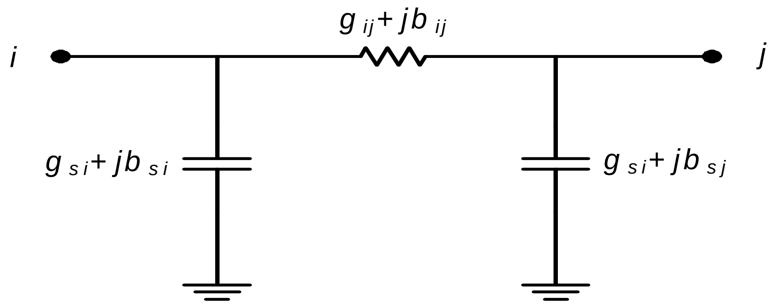

Fig. 5. Two-port π-model of a network branch

of the gain matrix. One way to reduce this burden is in line with the observation in section II.B.2, that the elements of the gain matrix do not significantly change between flat start initialization and the converged solution. Furthermore, as observed earlier for the power flow problem [23], sensitivity of the real (reactive) power equations to changes in the magnitude (phase angle) of bus voltages is very low, especially for high voltage transmission systems. These two observations lead to the fast decoupled formulation of the state estimation problem [24, 25]. In this formulation, the measurement equations are partitioned into two parts:

1. Real power measurements, including the real power bus injections and real power flows in branches. These measurements will be denoted by the subscript A, meaning the active measurements.

2. Reactive power measurements, including the reactive power bus injections, reactive power flows in branches and bus voltage magnitude measurements. These measurements will be denoted by the subscript R, meaning the reactive measurements.

The measurement and their related arrays can be partitioned based on the above designation:

$$
\begin{aligned}
z^T &= \begin{bmatrix} z_A^T & z_R^T \end{bmatrix} \\
H &= \begin{bmatrix} H_{AA} & H_{AR} \\ H_{RA} & H_{RR} \end{bmatrix} \\
R &= \begin{bmatrix} R_A & 0 \\ 0 & R_R \end{bmatrix}
\end{aligned}
$$

The following assumptions are used to obtain the fast decoupled state estimation algorithm:

1. Assume flat start operating conditions, i.e. all bus voltages beging at nominal magnitude of 1.0 p.u. and in phase with each other.

2. Ignore the off diagonal blocks H_{AR} and H_{RA} in the measurement Jacobian H, and compute the gain matrix using this approximation. This will also eliminate the off diagonal blocks in the gain matrix, yielding a constant and decoupled gain matrix evaluated at flat start:

$$
G = \begin{bmatrix} G_{AA} & 0 \\ 0 & G_{RR} \end{bmatrix}
$$

$$
\begin{aligned}
G_{AA} &= H_{AA}^T R_A^{-1} H_{AA} \\
G_{RR} &= H_{RR}^T R_R^{-1} H_{RR}
\end{aligned}
$$

3. Repeat the same approximation for the Jacobian entries when calculating the right hand side vector:

$$T = \begin{bmatrix} H_{AA}^T R_A^{-1} \Delta z_A \\ H_{RR}^T R_R^{-1} \Delta z_R \end{bmatrix} = \begin{bmatrix} T_A \\ T_R \end{bmatrix} \tag{2.15}$$

where:

$\Delta z_A = z_A - h_A(\hat{x})$,

$\Delta z_R = z_R - h_R(\hat{x})$.

The above assumptions lead to a decoupled solution algorithm using the polar coordinates in the calculations. Hence, the solution for the phase angle $\Delta\theta$ and magnitude ΔV updates are obtained alternatingly and convergence is tested based on the maximum changes in both of these arrays. The steps of the solution algorithm are given below:

1. Initialize all bus voltages at flat start, i.e. $V_i = 1$ p.u., $\theta_i = 0$ for all $i = 1, \ldots, N$.

2. Build and perform triangular decomposition of G_{AA} and G_{RR}.

3. Calculate T_A using (2.15).

4. Solve $G_{AA}\Delta\theta = T_A$.

5. Update $\theta^{k+1} = \theta^k + \Delta\theta$.

6. Calculate T_R.

7. Solve $G_{RR}\Delta V = T_R$.

8. Update $V^{k+1} = V^k + \Delta V$.

9. Check if both $\Delta\theta$ and ΔV are less than the convergence tolerance. If yes, stop.

10. Go to step 3.

Note that the gain sub-matrices G_{AA} and G_{RR} are computed and decomposed into their triangular factors only once at the beginning of the iterative solution. Solutions for $\Delta\theta$ and ΔV are carried out very efficiently using the forward and back substitutions, since the triangular factors need not be updated during the iterations. The dimension of the two gain sub-matrices are half the size of the fully coupled gain matrix, further reducing the computational effort.

F. Bad Data Detection

Measurements that are provided to a state estimator may contain errors. These errors may come from various sources. Random errors usually exist in measurements due to the finite accuracy of the meters. Large measurement errors may be caused by biased meter data, telecommunication system failures or unexpected noise.

Some bad data can be observed easily, e.g., negative voltage magnitudes, measurements that are significantly larger or smaller than expected value, etc. Unfortunately, not all bad data are easily detectable. Hence, state estimators need to be equipped with more advanced techniques to facilitate the detection and identification of bad data.

In this dissertation, the *normalized residuals* are used to detect bad data. Normalized value of the residual for measurement i can be obtained by simply dividing its absolute value by the corresponding diagonal entry in the residual covariance matrix:

$$r_i^N = \frac{|r_i|}{\sqrt{\Omega_{ii}}} = \frac{|r_i|}{\sqrt{R_{ii}S_{ii}}} \tag{2.16}$$

The normalized residual vector r^N will then have a Standard Normal distribution, i.e.

$$r_i^N \sim N(0,1)$$

Thus, the largest element in r^N can be compared against a statistical threshold to decide on the existence of bad data. The threshold can be chosen based on the desired level of detection sensitivity.

G. Summary

The basic theory of the power system state estimation has been introduced briefly in this chapter. A typical state estimator includes the following functions:

- Topology processing, which creates the bus-branch diagram of the system based on the connectivity of physical devices in the system and the status of circuit breakers and switches.
- Observability analysis, which determines whether a state estimation solution can be calculated using the available measurements.
- State estimation solution, which calculates the best estimate for the complex bus voltages in the system based on the network model and the gathered measurements from the system.
- Bad data processing, which detects errors in measurement data.

The theories and algorithms introduced in this chapter are used in the research topics covered in the following chapters. While some of the research topics are well defined, there is always room for improvement in the power system state estimation areas. For example, the network observability determines whether a state estimation solution can be obtained. The network observability is decided by the network topology and the way how measurements are placed. It is therefore important to arrange the limited measurement devices wisely to create a better solution of measurement placement. On the other hand, the network topology might change due to circuit breaker operations and may cause the network to lose its observability. How to deal with the loss of observability is also an interesting research topic. Finally, bad data processing is usually only capable of identifying bad data in analog measurements. In case of circuit breaker status errors, bad data processing may see multiple errors and is not able to detect the source of the error. Chapter III will talk more about these problems and corresponding solutions.

CHAPTER III

PROBLEMS TO BE SOLVED

A. Introduction

As mentioned in the previous chapters, there are many research topics related to the conventional state estimation. This dissertation will focus on three problems that affect state estimation.

The first problem is the measurement placement design problem. The locations of measurements have influence on the network observability and therefore are important to state estimation. A well-designed measurement placement scheme can reduce the cost of measurement equipment and installation. Fig. 6 shows the advantage of a good measurement placement design. In a sample 9-bus system, Scheme I uses 3 RTUs and 9 measurements to make the whole network observable. Scheme II uses 7 RTUs and 11 measurements, but Bus B3 is still unobservable. In order to make B3 observable, one more power flow measurement needs to be installed on either B3 or B9. It can be seen that Scheme I is better than Scheme II in the sense of reducing measurement costs. How to obtain such a good placement scheme remains an interesting research topic.

The second problem relates to the future trend of replacing RTUs with IEDs and front-end computers. Traditionally, RTUs are used to gather various types of measurements from the field and transmit them to the control center using SCADA system. The sampling rate of these RTUs is usually low and it is hard to pre-process the measurement before sending them out due to hardware limitations. Nowadays, multi-functional IEDs are being installed in the substations. Besides their own designed substation automation system (SAS) functions, these IEDs often record data

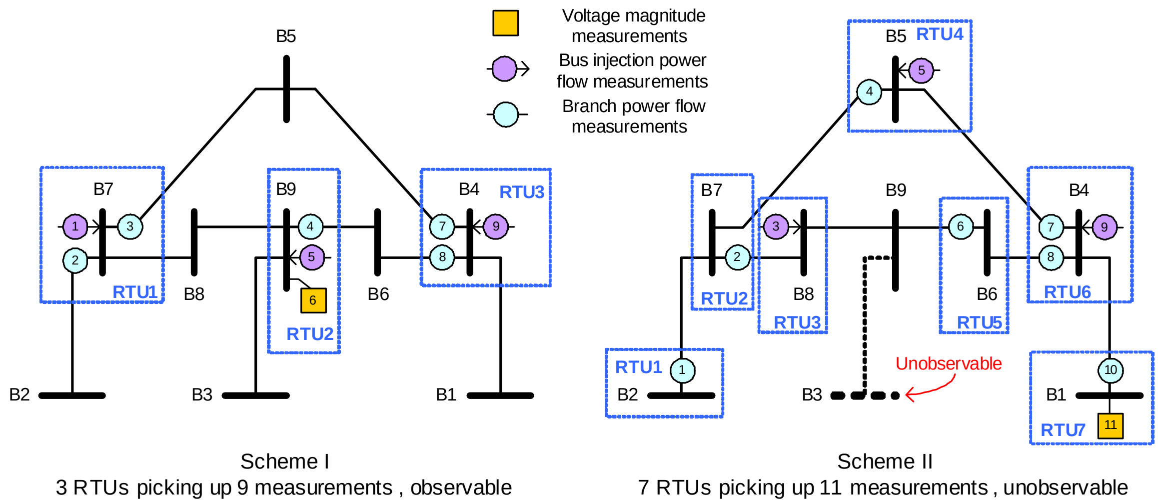

Fig. 6. Good scheme vs. bad scheme in measurement placement

that can be used for other monitoring and control purposes. It is possible to have a mixture of RTUs and IEDs connected to a front-end computer through local area network. The recorded data from different devices can be stored and pre-processed on the front-end computer before being transmitted to the control center. This brings new opportunities to utilize these locally available data for different power system applications, including power system state estimation. This dissertation will study how to make use of substation measurements to deal with the situation of loss of observability.

The third problem relates to the issue that the traditional state estimation technique is unable to identify topology errors. If a circuit breaker status is recorded incorrectly, usually the bad data detection function will see that several analog measurements appear to be bad data. State estimation results in this case are usually unacceptable. This dissertation will study the issue of topological error identification as another application of utilizing substation measurements.

This chapter will discuss these three aspects in power system state estimation, namely, the cost minimization in measurement placement, dynamic utilization of substation measurements and detection of topological errors.

Each of the following sections will talk about one aspect, starting with the existing approaches introduced through previous research and their limitation. This will be followed by a brief discussion of the problems that need to be solved.

B. Cost Minimization in Measurement Placement

1. Existing Approaches and Limitations

There is always a trade off between the cost and performance as the placement of measurements is considered. Reference [26] uses a general criterion to systematically eliminate some of the measurements in the system to obtain an optimal set of various measurements. Reference [27] compares the advantages and disadvantages of various methods of optimal measurement placement. References [28, 29] present ways to minimize the investment cost while improving the accuracy of the state estimation.

The focus of this dissertation is on the issue of reducing the overall cost of placing measurements, subject to the observability requirements of the network.

Some of the previous research on this kind of measurement placement problems are mainly related to the aspect of rendering an existing measurement system into a more robust one. In [30], methods have been presented for placement of new measurements in order to turn an unobservable system into an observable one. Reference [31] proposes a method for selecting additional measurement locations in order to increase local redundancy and strengthen network observability. References [32] and [33] talk about how to place additional meters in a way that will maintain full observability when measurements are lost from the system due to contingencies.

Other methods in the past focused on the optimal measurement placement planning from scratch. Reference [34] chooses the location of RTUs by comparing the total number of incident lines/transformers in substations and picking up substations with the largest number first. Reference [35] uses a similar method and puts RTUs on all substations in the network first, then removes the ones that are in substations with low number of incident lines/transformers until the observability constraints are not met. References [6, 36] use a two-stage method to reduce the number of RTUs by placing the measurements first and then adjusting some of the measurement types and locations. Reference [37] presents a genetic algorithm for the measurement placement optimization. A group of placement plans were randomly generated, and then the best one of them was picked.

The previous methods have limitations in various aspects. Some methods do not have very satisfying results and the proposed measurement placement schemes still cost a lot. This can be seen from Chapter VII, which shows the comparison of the results from previous methods and from the method proposed in this dissertation. Some methods are hard to implement. Part of the algorithm requires human observation and the performance of the results depends on human expertise. For example, [6] uses a two-stage optimization method for the measurement placement. Stage II reduces the number of RTUs by observing the results of Stage I. However, no universal algorithm has been provided for stage II. The results of some other methods depend on the initial population on which the optimization algorithm is employed, since the randomly generated measurement locations cannot cover all possible situations due to the computational limitation. For example, the method used in [37] has such a problem.

2. Problem to be Solved

Although several methods have been proposed on turning an unobservable system into observable, methods for placing state estimation measurements in the planning stage have not been studied thoroughly.

The network observability is determined by both the number of measurements and location of their deployment in the network. Usually, the more available measurements, the more likely that the system is observable and the system states can be estimated. The locations of the measurements also play an important role in deciding the network observability. A well designed measurement placement method can make the network observable using much fewer devices. The network observability may also change due to the changes in network topology or loss of measurements; therefore it is also desirable to have a measurement placement scheme that can endure certain types of network contingencies.

Besides the basic requirements for measurement placement as mention above, the proposed method should also address the limitations of previous methods. The proposed method from this dissertation will address the following problems:

1. The proposed measurement placement scheme applies to the situation when one is placing measurements in a power system from scratch. This scheme is helpful for system planning. This is similar to the scopes of [6, 34–37].

2. The measurement placement results must meet the observability requirements of the system, both under normal running mode and under certain contingencies. Three types of contingencies will be considered: the loss of a single branch, the loss of a single measurement, and the loss of a single RTU. The loss of a single branch situation was not considered in previous methods mentioned above. As a reasonable contingency, this situation will be considered in this dissertation.

3. The proposed method must be easy to implement and the algorithm should be fully computer-based. This requirement guarantees the applicability of the proposed method to larger scale systems.

4. The results of the proposed method should show clear advantages over existing methods.

C. Dynamic Utilization of Substation Measurements

1. Existing Approaches and Limitations

In a power system state estimator, a network topology processor determines the circuit breaker status in real-time to obtain electrical network topology.

The conventional network topology processor for the power system determines the connectivity in electrical node groups, which are sets of nodes that become a single bus when all switches and breakers are considered closed. In addition to switching devices, substations are associated with terminals of branch devices (e.g., transmission lines, transformers, phase shifters, and series devices), shunt devices (e.g., capacitors, reactors, synchronous condensers, static VAr compensators, loads and generators), and metering devices (e.g., power and current flow meters, power and current injection meters, and voltage magnitude meters) as well. The connection of these devices are also processed by the NTP as they are assigned to different buses in a bus-branch model [7]. The measurement data gathered by metering devices are mapped into state estimation measurements by methods described in Chapter II.C.

The network topology in a power system is altered due to the changes of CB status in substation. The opening or closing of CBs may cause the network topology to change significantly and result in totally different bus-branch model. In a conventional NTP, many substation measurements are simply discarded because their positions in the simplified bus-branch network model are lost. These measurements cannot be used in the network observability analysis and when some of the used measurements are lost, an estimate of system states may not be feasible. The existing approaches to deal with the loss of observability is to add more measurements to the network [31–33], which can only be done off-line.

2. Problem to be Solved

The focus of this dissertation on this topic is to develop a better NTP that generates more state estimation measurements out of the available substation metering devices data. The proposed algorithm goes beyond simply taking substation RTU and IED measurements as the input data of a state estimator. Instead, measures should be taken to see the possibility to calculate new measurements that are not directly taken from the field.

Fig. 7 illustrates the situation of power flow measurements calculation. P1, P2 and P3 are three IEDs that record power flows. The power flows of CB1, CB2 and CB6 are not directly measured. However, by observation, we can calculate power flows of CB1, CB2 and CB6 as follows, assuming all the CB statuses are correct:

$$\begin{aligned} P_{CB1} &= -P1 \\ P_{CB2} &= P_{CB1} - P2 = -P1 - P2 \\ P_{CB6} &= -P3 \end{aligned}$$

How to find out such implicit relationship among substation measurements is the problem to be solved. A numerical matrix may represent the physical connectivity of substation devices. It can then dynamically search for solutions to calculate

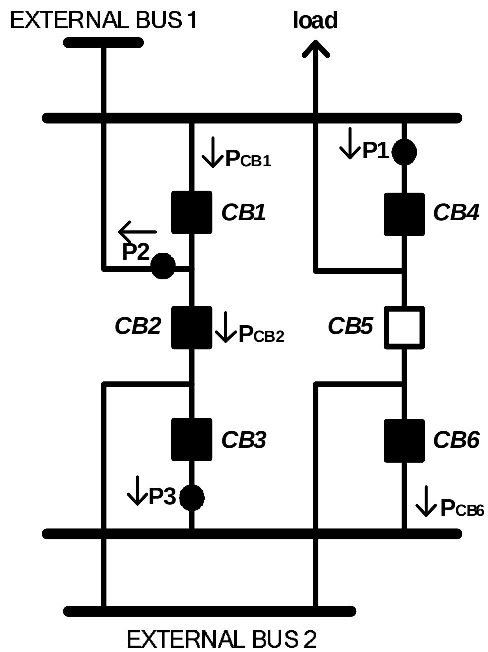

Fig. 7. An example of substation measurements

branch and bus injection power flow measurement data using the linear combination of the available substation measurement data. By using this method, those discarded substation measurements may still be used and more state estimation measurements may be created instantly without the need to install new physical devices.

D. Detection of Topological Errors

1. Existing Approaches and Limitations

The problem of topological error detection on power system state estimation refers to the identification of errors in the measurements of circuit breaker status. The correct statuses of all CBs in the system are typically known almost all the time. In some cases, the assumed status of certain CBs may be wrong. When this happens, the bus/branch model generated by the topology processor is incorrect, leading to a topological error. Topological errors usually cause the state estimate to be significantly biased. As a result, the bad data detection and identification function may see many analog measurements as unacceptable bad data and it is usually very hard to tell what is the cause of the bias. There is a need to develop effective mechanisms intended to detect and identify this kind of topology errors.

There are several rule-based methods [38–41] and methods using correlation index [42] as an indication of possible topology errors. Other approaches [43, 44] utilize normalized measurement residuals to identify topology errors. In early 1990's, Monticelli presented a new modeling method, which includes switches directly in the system model by incorporating their power flows within the state estimation formulation [45, 46]. Several topology error identification algorithms [47–50] were proposed based on this model. The main idea was to augment the state vector with the power flows through the circuit breakers and identify the status of the breakers based on the estimated flows through them. This was accomplished by representing the substations in detail using circuit breaker models.

A major problem about the topology error identification is the size of state variables. The inclusion of all details of substations will introduce too many variables into the state vector, and thus make it impossible to run the state estimation efficiently. Techniques to reduce the number of state variables have been proposed in recent studies. One technique is to employ detailed substation models for a few substations suspected of having topological errors. A two-stage state estimation [47, 51] is used for this purpose. A small set of suspect substations is identified after the first stage estimation. The second stage state estimation incorporates the detailed model of the suspected substations and yield the estimated statuses of the CBs. Another technique is the substation graph and reduced model [52, 53], which, by properly exploiting the topological properties of circuits, adds only a subset of power flows through switching devices to the state vector. This technique allows the detailed modeling of the entire network at little computational overhead while analyzing bad data and topology errors at the same time. However, The selection of extra state variables is difficult and may require human decisions.

2. Problem to be Solved

Most methods mentioned earlier require the modification of the state estimator to include the state variables that relate to CB power flows or voltage drops. Besides the burden of extra computation complexity, it is also inconvenient for application and testing in the real world. The state estimators currently running in utilities have fairly complex software solution and any modifications may take a lot of effort.

The modification of state estimator is what this dissertation will try to avoid. Instead, the proposed method will be rule-based and it will only modify the topology processor. Different from previous rule-based methods, this dissertation will attack the topological error detection problem using the idea of improved topology processing. The basic idea is to verify CB status using both direct and calculated substation measurements. The same algorithm as used in solving the dynamic utilization of substation measurements problem will be used to calculate those inferred substation measurements. The proposed topological error detection is implemented as an extension of the dynamic utilization of substation measurements function. The proposed algorithm should handle the situation when no power flow measurement is allowed to the CB being verified. Instead of looking at each CB and its corresponding measurements, the proposed method should generate a power flow pattern in a substation as a entire picture from the available measurements. After that, CB statuses can be verified against a set of rules based on the power flows.

E. Summary

This chapter introduces three aspects in power system state estimation that need improvement. In the area of measurement placement, an efficient design scheme to place limited number of measurement devices to make the whole network observable is lacking. In the aspect of network topology processing, many substation metering devices are discarded during the topology processing and how to make use of them dynamically during the changes of network topology remains an unsolved problem. Regarding the detection of topological errors, many previous methods require changes to be made to the state estimator, which is much harder to implement than to modify the topology processor.

This dissertation will address these three problems and offer solutions. The following chapters will discuss the proposed methods for the improvements.

CHAPTER IV

COST MINIMIZATION IN MEASUREMENT PLACEMENT

A. Introduction

The cost of measurement placement for the purpose of state estimation usually comes from the following:

1. Measurement transducers. These devices are needed to obtain measurement data from the measurement apparatus such as current transformers (CTs), voltage transformers (VTs), and CB status measurements relays. Each measurement point needs to be assigned a transducer, so that the parameter being measured can be converted to a standard 4-20mA DC signal.

2. RTUs. An RTU needs to be installed in a substation, if one or more measurements from this substation need to be transmitted to the EMS. An RTU is capable of gathering the DC signals converted by the transducers from both analog measurements (such as power flows and voltage magnitudes) and digital measurements (such as CB contacts). Each measurement needs to be assigned a separate input channel.

It can be seen that the cost of state estimation measurements is decided by the number of measurements and RTUs. To minimize the cost associated with measurement placement, the least number of measurements should be used. Also, these measurements should appear in as few substations as possible, so that the number of RTUs can also be reduced. Currently, transducers can be built at fairly low cost [34]. The price of transducers is much lower than the price of an RTU. Therefore, reducing the number of necessary RTUs is especially important in the cost minimization.

There are three options regarding the placement of RTUs in a power system [34]:

1. Placing RTUs at all substations to gather the information of the network topology status (the position of switches and breakers) and all the analog measurements like active/reactive power flow, bus voltage magnitude, etc.

2. Placing RTUs at all substations to gather the network topology status. Analog measurements are gathered only at selected substations.

3. Placing RTUs at selected substation to obtain the network topology status and analog measurements. The remaining topological information from other substations is updated off-line manually.

Option 1) is the most desirable one but it is also the most costly. Option 2) can save some cost from 1) by reducing the number of analog measurements. Option 3) is the most economical way at the expense of not being able to update the network topology on-line.

It is also assumed that there are enough input channels in each RTU. As discussed in [6], modern analog-to-digital (A/D) converter in RTUs can deal with more than 100 analog measurement inputs per second. Considering that the number of analog measurements required by the state estimation in a single substation is usually far lower than 100, it is safe to assume that the limitation of RTU channels is not a problem. The cost of each channel is still not trivial due to the interfacing cost, hence it is also a desirable goal to have fewer channels.

The proposed method for placing measurements consists of two steps, which will be discussed in detail below.

B. Proposed Approach

1. Consideration of Observability Constraints

The first and most important constraint of a measurement placement scheme is that the measurements must make the network observable under normal running conditions. In this paper, the branch power flow and bus voltage magnitude measurements are placed to meet this requirement.

As described in section II, whether a network is observable depends on whether a spanning tree can be formed using the existing measurements. Since branch power flow measurements are assigned to their corresponding branches, the network observability is therefore determined by checking whether the branches whose power flows are measured can form a spanning tree of the whole network. It is known that for an n-bus network, the spanning tree consists of n-1 branches. Therefore, at least n-1 branch power flow measurements are needed to make the network observable.

There are many ways to form a spanning tree. The task of branch measurement placement is to decide how to form the spanning tree so that measurements are concentrated in fewer substations rather than scattered all over the network. Since a single RTU is capable of obtaining all measurements from a single substation, a "concentrated" measurement placement scheme would be preferable, as fewer RTUs are needed. A thorough enumeration of all possible solutions is practically impossible. Some kind of heuristic method must be used.

In order to describe the algorithm of the new method, two terms are defined first. The *degree* of a bus is the total number of branches connected to this bus. A bus B1 is called to be *adjacent* to a bus B2, if there is a branch between B1 and B2.

The flowchart of the algorithm is shown in Fig. 8. An example of the algorithm for placing the branch power flow measurements in the IEEE 14-bus system is

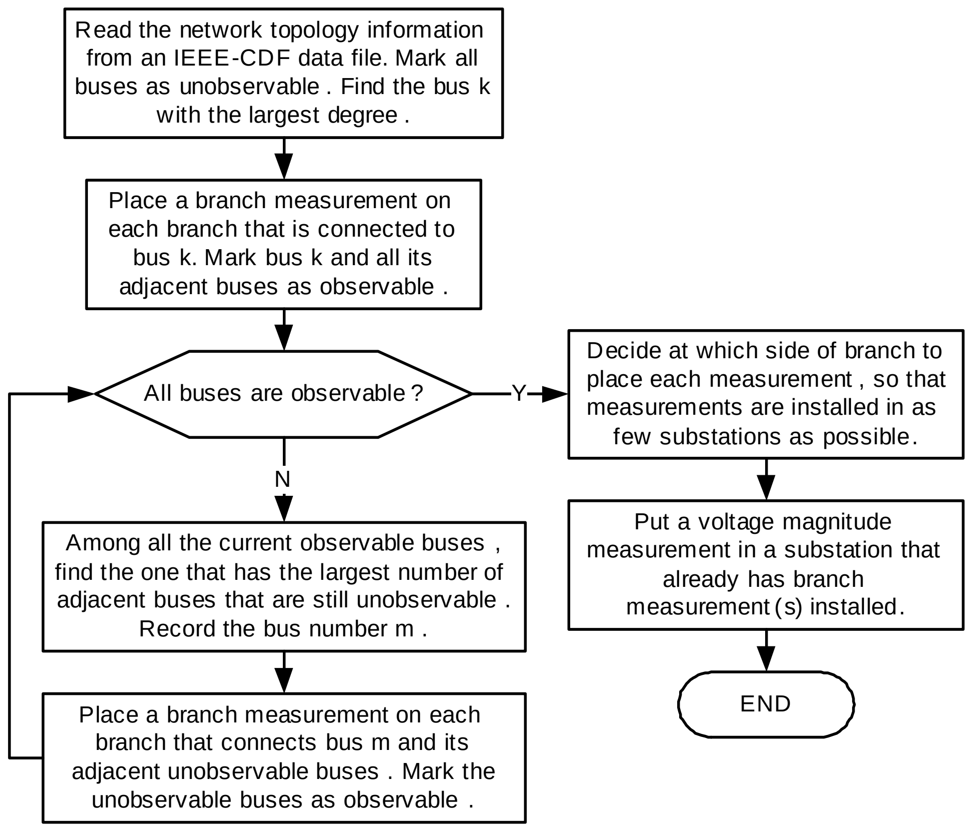

Fig. 8. Flowchart of the branch power flow and voltage magnitude measurement placement

demonstrated in Fig. 9. The explanations of the 7 steps are as follows:

- Step 1: No measurement is placed in the network. All branches are represented in dashed lines, which means that none of them has an assigned measurement. All the buses are gray, which means that they are unobservable.
- Step 2: Bus 4 is found to be the bus of the largest degree (five). Place one branch power flow measurement on each of these five branches, and mark the branch using a solid line. Mark bus 4 and its five adjacent buses as observable (black).
- Step 3: Among all the current observable buses, find the one that has the largest

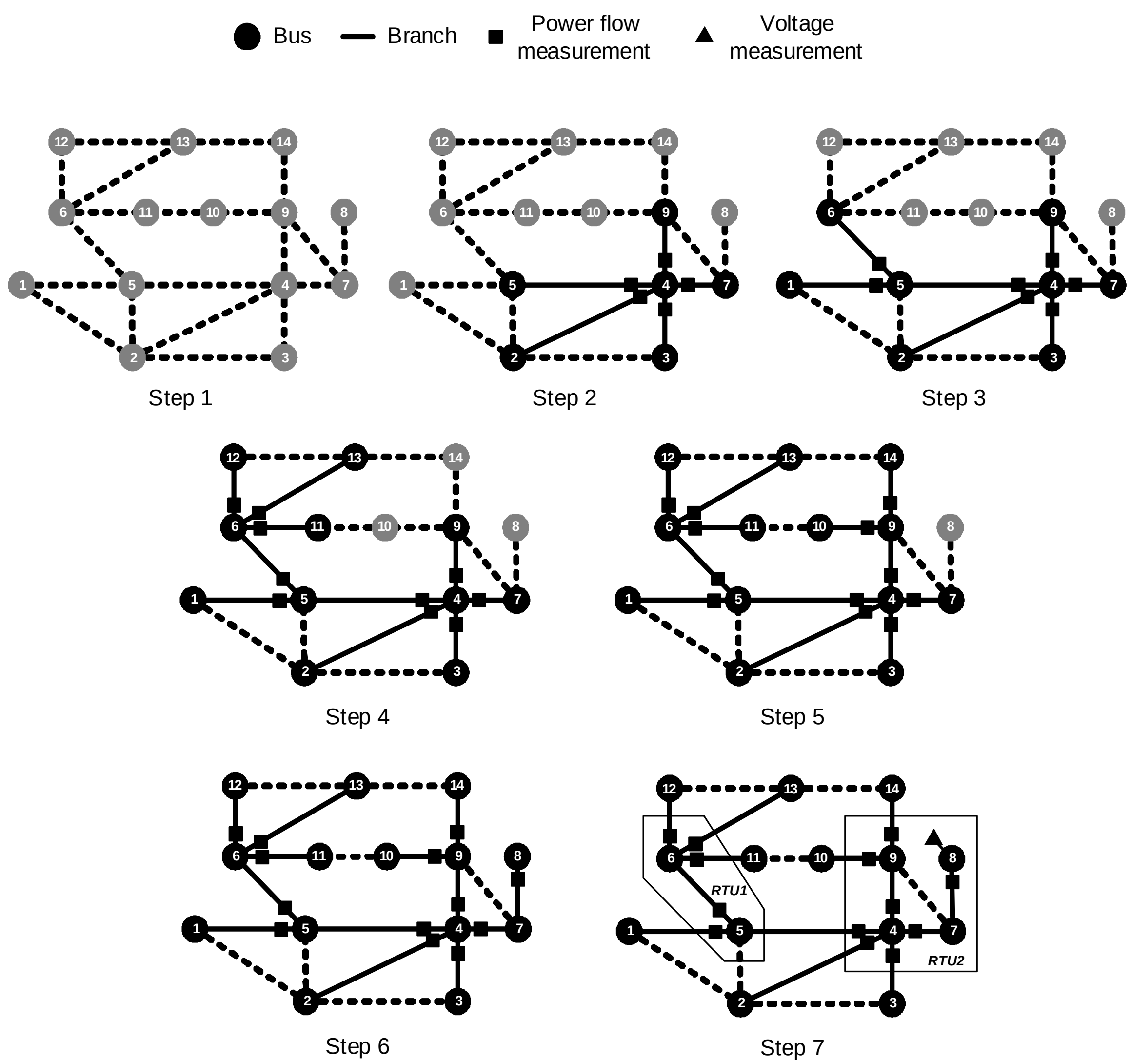

Fig. 9. Branch measurement placement in the IEEE 14-bus system

number of adjacent buses that are still unobservable. Bus 5 is one of such buses. Place a branch power flow measurement on branches 5-1 and 5-6 respectively, so that bus 1 and 6 become observable. Note that no branch measurement should be placed on 5-2, since bus 2 is already observable.

- Step 4: Using the same criteria as in step 3, bus 6 is found to be the next eligible bus to be processed. Place branch power flow measurements on 6-11, 6-12 and 6-13. Buses 11, 12 and 13 become observable.

- Step 5: Using the same criteria as in step 3, bus 9 is found to be the next eligible bus to be processed. Place branch power flow measurements on 9-10 and 9-14. Buses 10 and 14 become observable.

- Step 6: Using the same criteria as in step 3, bus 7 is found to be the next eligible bus to be processed. Place branch measurements on 8-7 (bus 7 is inside a three-winding transformer and therefore the measurement should be placed at the bus-8 side). Now the spanning tree has been formed for the network and all buses are observable.

- Step 7: It is found out that all branch measurements are installed in two substations - substation (5,6) and substation (4,7,8,9). A voltage measurement is chosen to be placed on Bus 8 in substation (4,7,8,9). Only two RTUs are needed to gather all the measurements.

It can be seen that at the end, the IEEE-14 bus system is made observable by 1 voltage magnitude measurement, 13 branch power flow measurements and 2 RTUs. It should be noted that these numbers correspond to the least possible number of measurements and RTUs in order to make the IEEE 14-bus system observable. Therefore, the proposed algorithm has found the most economical measurement placement

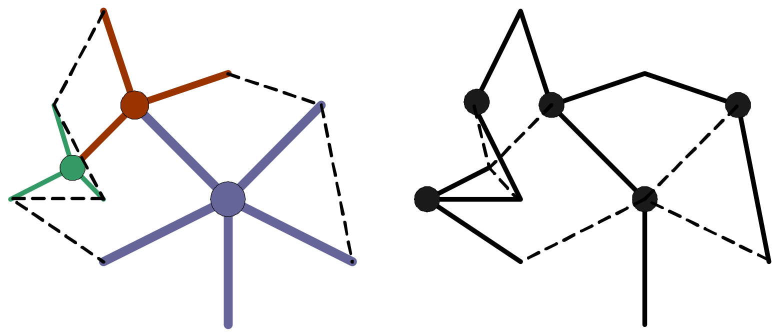

Fig. 10. Comparison of spanning trees

scheme that preserves observability under normal running conditions.

The proposed algorithm picks the buses with the most number of branches first, therefore a more concentrated measurement placement scheme will be generated. Such a scheme may reduce the number of RTUs needed. Fig. 10 illustrates the idea of the proposed algorithm. In the figure, a hypothetical network is shown. solid lines represent branches that are chosen as the spanning tree branches. Dashed lines represent other branches that are not chosen. Solid circles represent substations where RTUs are installed. The proposed algorithm pick up the buses one by one and the spanning tree is expanded into a radial shape. Only 3 RTUs are needed for the spanning tree to reach all buses. The randomly picked spanning tree, on the other hand, requires 5 RTUs to reach all buses. The proposed algorithm results in a better measurement placement scheme in the sense of cost minimization.

In a large network, the theoretical best measurement placement scheme requires thorough searching of all possible options. With the increase of network size, the number of placement options increase exponentially, making it impossible to test all cases. The computation complexity of the proposed algorithm approximately increases linearly with the increase of network size, therefore it can be easily applied to larger system networks. Although it is not likely that the very best solution can be obtained, the proposed method encourages the computer to search in the direction of a better solution and usually results in a quite satisfactory one.

2. Consideration of Reliability Constraints

Besides the observability constraint under normal running conditions, it is often desirable to maintain the network observable under certain contingencies. The following contingencies are usually taken into consideration:

1. The loss of any single measurement.

2. The loss of any single RTU.

3. The loss of any single branch in the network.

This part talks about how to add bus injection power flow measurements to deal with such contingencies.

To preserve the network observable under the loss of any single measurement, it is required that the network has no critical measurement. There are known ways to identify critical measurements in the power system network [35, 54]. Once a critical branch power flow measurement is found, it can be converted to a non-critical measurement by placing a bus injection power flow measurement at either end of the branch. With the help of the extra bus injection measurement, the loss of the branch measurement will no longer affect the network observability. This procedure should be repeated for every single critical branch power flow measurement in the network.

To maintain the network observability against the loss of any single RTU, more RTUs need to be installed. Since the proposed method tries to assign many measurements to the same RTU, the loss of a single RTU may cause the loss of many measurements simultaneously, and in turn the loss of observability. Because of this situation, a simple method is used: installing a backup RTU in every substation that has measurements. This approach simply doubles the number of RTUs in the basic measurement placement design described in section B. All measurements in the substation feed both RTUs simultaneously. In the case of the primary RTU loss, the backup RTU will continue transmitting measurement data to the control center.

To deal with the situation of the loss of any single branch, the branches are temporarily disconnected from the network one at a time and a network observability analysis is then carried out. If the network is found to be unobservable, unobservable branches should be identified using the method described in [11]. In such a situation, the network will be rendered observable again if a bus injection power flow measurement is placed on either end of any one of the unobservable branches. This procedure should be repeated until every single branch has been tested.

C. Summary

This chapter proposes a new algorithm for cost minimization in the measurement placement design for the purpose of state estimation. The new algorithm is developed based on topological observability analysis method, and therefore is faster than the numerical methods. Two levels of measurement placement designs are obtained: the basic level design guarantees the whole network to be observable using only the voltage magnitude measurement and the branch power flow measurements. The advanced level design keeps the network observable under the following contingencies:

1. The loss of any single measurement, by eliminating the critical measurements in the network.

2. The loss of any single RTU, by installing a backup RTU in every substation

that has measurements.

3. The loss of any single branch in the network, by temporarily disconnecting branches one by one and running observability analysis.

CHAPTER V

DYNAMIC UTILIZATION OF SUBSTATION MEASUREMENTS

A. Introduction

In a substation, CB statuses may be changing relatively frequently, either due to faults, or because of operator commands. The network topology changes accordingly. The changes in topology may have the following potential impacts on the NTP:

1. The merging or splitting of buses may cause some substation measurements to become useless in the changed topology, during the processing of measurement data as described in section II.

2. Some measurements may be disconnected from the rest of the network. For example, when the CBs disconnect a transmission line, the branch power flow measurement on this line is also disconnected and will not appear in the bus-branch model.

3. The total number of available measurements in the bus-branch model may be reduced and the locations of measurements may change, due to the change of network topology.

Because the network observability is highly related to the number and locations of measurements in the network, the network may become unobservable after the change of topology, and therefore an estimation of system states cannot be obtained.

The existing approach to deal with the loss of observability is to suggest new locations for additional measurements [31–33]. Installing new measurements may be costly and can only be done off-line. A way of utilizing the currently available measurements in the substations to recover the network observability on-line is presented in this section. The new method is called the dynamic utilization of substation measurements (DUSM).

B. Proposed Approach

1. Calculation of Inferred Substation Measurements

Like a conventional NTP, the first step of DUSM is to read in the static connections of devices and CB statuses, and then store the network topology information in an organized way for easier processing.

Substation power apparatuses such as CBs, branches, loads, generators, etc. are grouped into different substations. Each device is assigned a "virtual" measurement that supposes to measure the power flow of this power apparatus, and a measurement vector can be as created using the following equation:

$$z_i = \left[\begin{array}{cccc} z(\text{device }1) & z(\text{device }2) & \cdots & z(\text{device }n) \end{array} \right]^T \tag{5.1}$$

where i is the substation number, device $1, 2, \cdots n$ are the power apparatuses of substation i, and $z(\text{device } j)$ is the power flow measurement of device j.

The following assumptions are made regarding the directions of the measurements:

1. A CB power flow measurement's direction is always the same as the CB's.

2. A branch power flow measurement's direction is always going into the node that the branch is connected to.

3. A power injection measurement's direction is always going into the node that it is connected to, i.e., for a generator, the measurement value is positive; for a load, the measurement value is negative.

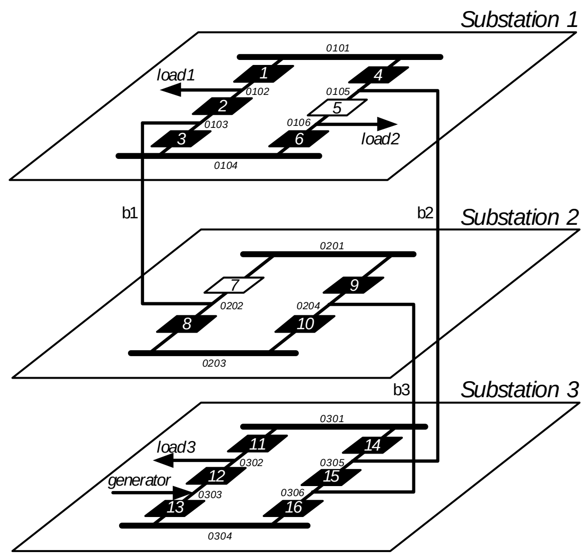

Fig. 11. Sample detailed substation model of a 3-bus system

If the directions of measurements are different from the above assumptions, they can be easily modified to conform to the assumption by changing the signs of the measurement values.

DUSM uses a three-dimensional incidence matrix M to store the topological information, as illustrated in Fig. 11 and Table I-III. The element of the incidence matrix M can be expressed as

$$M_i(y,x) = \begin{cases} 1 & \text{If measurement } x\text{'s direction goes into node } y. \\ -1 & \text{If measurement } x\text{'s direction goes out of node } y. \\ 0 & \text{If measurement } x \text{ is not incident to node } y. \end{cases}$$

where i is the substation number. Open CBs are not included when M is formed in order to take the advantage of the implicit constraint that the power flow through an open CB is always zero.

According to Kirchhoff's current law, we have

$$M_i \cdot z_i = 0 \tag{5.2}$$

Table I. Topological Information Storage for Substation 1

Substation 1		Devices								
		CB1	CB2	CB3	CB4	CB6	load1	load2	b1	b2
Nodes	0101	-1	0	0	-1	0	0	0	0	0
	0102	1	-1	0	0	0	1	0	0	0
	0103	0	1	-1	0	0	0	0	1	0
	0104	0	0	1	0	1	0	0	0	0
	0105	0	0	0	1	0	0	0	0	1
	0106	0	0	0	0	-1	0	1	0	0

Table II. Topological Information Storage for Substation 2

Substation 2		Devices				
		CB8	CB9	CB10	b1	b3
Nodes	0201	0	-1	0	0	0
	0202	-1	0	0	1	0
	0203	1	0	1	0	0
	0204	0	1	-1	0	1

Table III. Topological Information Storage for Substation 3

Substation 3		Devices									
		CB11	CB12	CB13	CB14	CB15	CB16	gen.	load3	b2	b3
Nodes	0301	-1	0	0	-1	0	0	0	0	0	0
	0302	1	-1	0	0	0	0	0	1	0	0
	0303	0	1	-1	0	0	0	1	0	0	0
	0304	0	0	1	0	0	1	0	0	0	0
	0305	0	0	0	1	-1	0	0	0	1	0
	0306	0	0	0	0	1	-1	0	0	0	1

where i is the substation number.

In a practical system, some of the elements in z_i are measured while others are not. The measured elements can be replaced by their measurement values, while other elements remain as unknown. What we are interested in is to infer as many measurement values as we can by using (5.2).

It can be seen that an inferred measurement can be calculated when the measurements of all other devices that are connected to the same node are available. This can be illustrated by the following example. In Fig. 11, suppose the power flow of CB8 is measured and its value is z_8. For illustration purpose, the configuration of Substation 2 is re-drawn in Fig. 12.

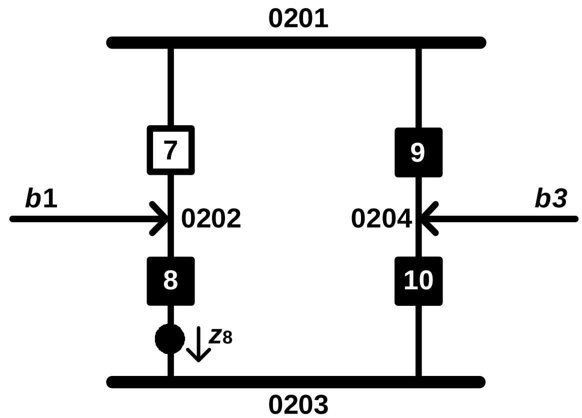

Fig. 12. Configuration of substation 2 with one measurement

Applying (5.2) to node 0202, we get:

$$\begin{bmatrix} -1 & 0 & 0 & 1 & 0 \end{bmatrix} = \begin{bmatrix} z_8 \\ z_{CB9} \\ z_{CB10} \\ z_{b1} \\ z_{b3} \end{bmatrix} = 0 \tag{5.3}$$

or $z_{b1} = z_8$, which means the power flow of branch $b1$ equals the power flow of CB8. Now that z_{b1} has been calculated, both z_8 and z_{b1} can be used to calculate other inferred measurements, until no more measurements can be inferred. The steps for measurements calculation for a certain substation i can be summarized as follows:

1. Gather all available substation power flow measurements and record them in vector z_i.

2. Search every row of matrix M_i for non-zero entries. For each device corresponding to a non-zero entry, check z_i to see if the power flow measurement is available for this device. If not, flag the entry as "unknown".

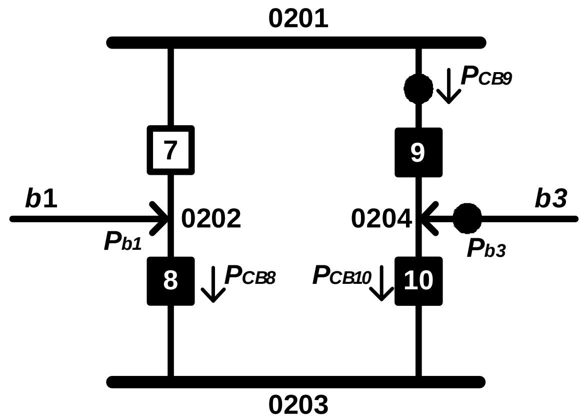

Fig. 13. Configuration of substation 2 with two measurements

3. If only one non-zero entry is "unknown" in a row, calculate it using Kirchhoff's current law. Record the inferred measurement value in z_i. Delete the "unknown" flag of this entry.

4. If there is no new inferred measurement found during the last round of searching, stop. Otherwise, go back to 2.

The procedure of measurement calculation will be illustrated below. In Substation 2 from Fig. 11, assume two power flow measurements P_{CB9} and P_{b3} are available. Fig. 13 shows the substation configuration. Using DUSM algorithm, it can be seen that power flows of CB8, CB10 and b1 can all be inferred. Fig. 14 shows the steps of calculation.

2. Calculation of Bus-branch Measurements

Once all possible inferred measurements are obtained, the next step is to calculate the values of the bus voltage magnitude measurements, bus injection power flow measurements and branch power flow measurements.

The calculation of bus voltage magnitude measurements is straight-forward. It

Substation 2		Devices				
		CB8	CB9	CB10	b1	b3
Nodes	0201	0	Measured	0	0	0
	0202	-1	0	0	1	0
	0203	1	0	1	0	0
	0204	0	Measured	-1	0	Measured

Step 1

Substation 2		Devices				
		CB8	CB9	CB10	b1	b3
Nodes	0201	0	Measured	0	0	0
	0202	-1	0	0	1	0
	0203	1	0	Inferred	0	0
	0204	0	Measured	Inferred	0	Measured

Step 2

Substation 2		Devices				
		CB8	CB9	CB10	b1	b3
Nodes	0201	0	Measured	0	0	0
	0202	Inferred	0	0	1	0
	0203	Inferred	0	Inferred	0	0
	0204	0	Measured	Inferred	0	Measured

Step 3

Substation 2		Devices				
		CB8	CB9	CB10	b1	b3
Nodes	0201	0	Measured	0	0	0
	0202	Inferred	0	0	Inferred	0
	0203	Inferred	0	Inferred	0	0
	0204	0	Measured	Inferred	0	Measured

Step 4

Fig. 14. Illustration of a measurement calculation procedure

can be done by a direct mapping of the substation node to the corresponding bus, as show below:

$$V_i = V_n \tag{5.4}$$

where n is the node number in the substation model, i is the bus number of n in the bus-branch model.

The calculation of branch power flow measurement uses the following rules:

1. If there is only one branch (single line) between two buses, map the branch measurement in the detailed substation model to the corresponding branch measurement in the bus-branch model by changing the node numbers to the bus numbers.

2. If more than one branch (multiple lines) exists between two buses, sum up all branch measurements in the substation model to get the branch measurement in the bus-branch model.

The bus injection power flow measurement can be calculated by adding all nodal injection measurements in a single merged electrical bus. If any measurement value is unknown after the addition, the injection power flow of this bus cannot be calculated.

C. Summary

This chapter explains the importance of an advanced network topology processor in preserving as many substation measurements as possible to maintain the network observability. A new method - the dynamic utilization of substation measurements (DUSM) - is presented. Instead of seeking the installation of new measurements in the system, this method tries to calculate meaningful state estimation measurement values by applying the current law that regulates different measurement values implicitly. Its processing is at the substation level and therefore can be implemented independently in different substations.

Chapter VII shows the implementation of DUSM in a power system network and the results of DUSM are compared with the traditional topology processor. The contribution of inferred substation measurement to the network observability is also discussed there.

CHAPTER VI

IMPROVED DETECTION OF TOPOLOGICAL ERRORS

A. Introduction

This chapter introduces a new way to verify substation circuit breaker status. The new method is a rule-based method that uses the DUSM.

First, the rules to determine whether a circuit breaker is OPEN or CLOSED are proposed. After that, the algorithms for topological error detection using direct measurements and inferred measurements are introduced respectively.

B. Proposed Approach

Reference [11] categorizes topology errors as follows:

- *Branch status errors*: Errors affecting the status of network branches with non-zero impedances (transmission lines or transformers). An *exclusion error* occurs when an energized branch is excluded from the model. An *inclusion error* happens when a disconnected branch is assumed to be in service.

- *Substation configuration errors*: Errors of CB status whose purpose is to link bus sections within the substation. A *split error* arises when a single electrical bus is modeled as two buses. A *merging error* happens when two electrical buses are modeled as a single bus.

It is also pointed out in [11] that for exclusion and split errors, when the power flow through the respective branch or CB is negligible, there is no way to detect the topology error, but there is no need to worry either, since the influence of topology errors on state estimation is small and the estimation results will be acceptable.

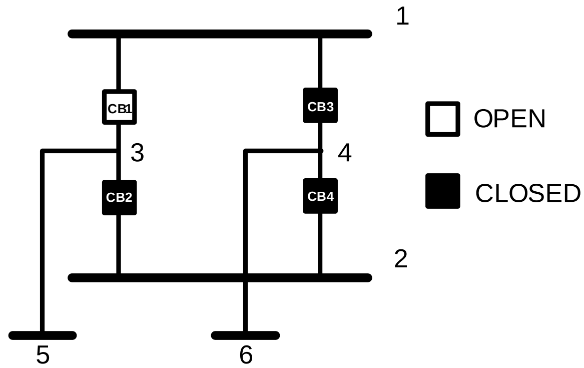

Fig. 15. An example of a critical CB pair

The characteristics of topology errors mentioned above will be the basis of the rules to determine CB status in this dissertation. It is well known that the power flow going through a CB is zero when the CB is OPEN. However, when the CB power flow is zero, the actual status of the CB can still be CLOSED. This situation is illustrated in Fig. 15. it can be seen that CB1 and CB3 form a serial branch. If either one of them is OPEN, this branch is disconnected. Under such a situation, no branch status error will occur, no matter if the other breaker is OPEN or CLOSED. Such a pair of CBs is referred to as a *critical pair* [55]. Under such a situation, the power flows going through CB1 and CB3 are both zero. In this dissertation, the status of both CB1 and CB3 will be assumed to be OPEN in this case, since there is no way to tell whether both breakers are OPEN, or only one of them is OPEN. By doing so, node 1 will be modeled by the topology processor to be a separate bus from the rest of the substation nodes, causing a split error in substation configuration. However, this has little influence on the state estimation since the power flow of CB3 is zero. On the other hand, it is not safe to assume CB1 as CLOSED, since doing so might cause a merging error or an inclusion error, in which case the state estimation results will be greatly affected.

Table IV. Determination of CB Status

Power flow value	Indicated CB status
Non-zero	CLOSED
Zero	Can be either OPEN or CLOSED. However, the CB status is "effectively" OPEN, which means it is safe to assume it to be OPEN and the assumption has little effect on the results of state estimation.

Based on the above observation, the rules to determine CB status are shown in Table IV.

Furthermore, the verification conclusions defined in the identification of the topological errors function are listed in Table V. First, the CB status is determined using the criteria listed in Table IV. Then, the determined CB status is compared with the reported CB status. Conclusions are given based on the comparison result.

1. Using Direct Measurements

Based on the criteria mentioned above, the CB status can be verified against its power flow measurement, if such a measurement is available. Using the direct measurements, the CB status verification procedure can be summarized as follows:

1. Obtain the active and re-active power flow measurement values (P and Q) of the CB.

2. Calculate $S = \sqrt{P^2 + Q^2}$, if P and Q measurements are available. Otherwise, consider S as not calculable.

3. Verify the CB status according to Table V and report the conclusions.

Table V. Conclusions of CB Status Verification

Power flow value	Reported CB status	Verification conclusion
Non-zero	CLOSED	The CB status is CORRECT.
	OPEN	The CB status is WRONG.
	UNKNOWN	The CB status is verified to be CLOSED.
Zero	CLOSED	The CB status can be considered as WRONG. The actual status may indeed be CLOSED, but in order to guarantee the correctness of state estimation, it should be assumed OPEN.
	OPEN	The CB status can be considered as CORRECT. The actual status might be CLOSED, but it is safe to assume it to be OPEN.
	UNKNOWN	It is safe to assume the CB status to be OPEN.
Cannot be measured or calculated	CLOSED	The CB status is unverifiable.
	OPEN	The CB status is unverifiable.
	UNKNOWN	The CB status is unverifiable.

4. Update the CB status in the network topology information according to the verification conclusions.

2. Using Inferred Measurements

The method described in Chapter V is also capable of calculating the CB power flows according to the available measurements in a substation, therefore it can also used as the algorithm of the determination of CB statuses. Once the CB power flows are calculated, the CB statuses are determined accordingly.

The algorithm for the detection of topological errors using inferred measurements can be seen in Fig. 16. First, CB statuses are verified using direct measurements, as described in Section VI.B.1. The results of the first-round verification are used to form the measurement-branch incidence matrix used in DUSM. When forming the measurement-branch incidence matrix, only the CLOSED and UNKNOWN CBs are collected. OPEN CBs, on the other hand, are considered as open circuit branches and left out of the measurement-branch incidence matrix. DUSM will then calculate the inferred CB power flow measurements. If there are any new inferred measurements during the last round of DUSM execution, another round of verification is needed. The procedure continues until no new inferred measurement is generated. The final CB statuses are then compared with the reported statuses to spot any topological errors.

Using inferred measurement to verify CB status is a new idea proposed in this dissertation. This makes it possible to verify a CB's status without a physical measurement being available.

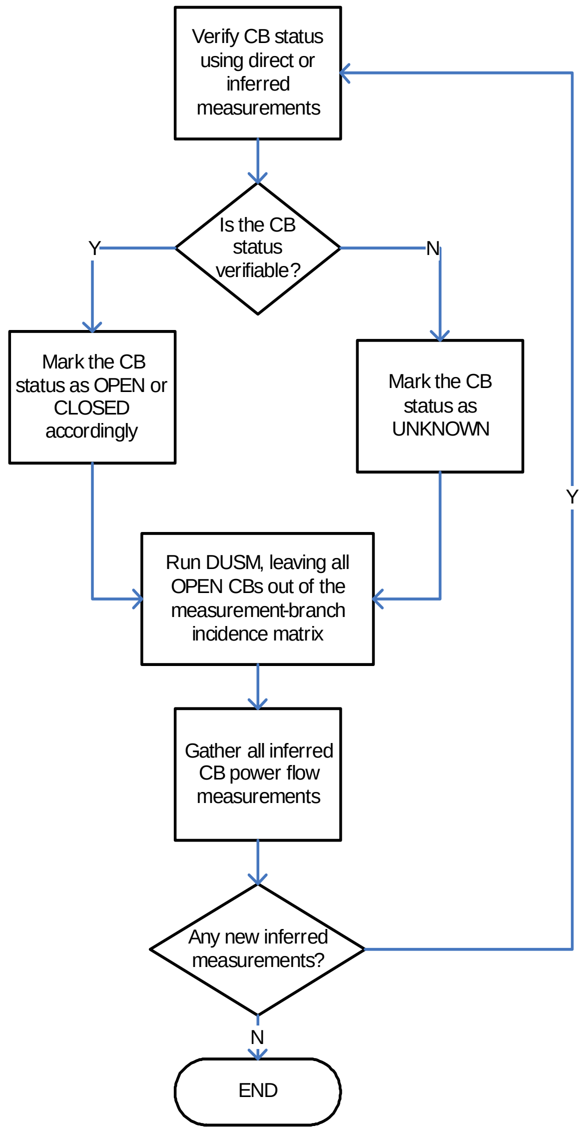

Fig. 16. Verification algorithm using inferred measurements

C. Summary

This chapter introduces the way to improve topological error detection using the method of DUSM. It can be seen that without modifying the state estimator, the status of a circuit breaker may still be verified even without direct power flow measurements. This is done by using inferred measurements calculated by DUSM.

Chapter IV, V and VI have introduced three new functions that are proposed by this dissertation. The next chapter will show the test scenarios and results of these new functions.

CHAPTER VII

CASE STUDIES

A. Introduction

This chapter summarizes some of the results that were gathered during the testing of the three proposed functions. In each of the following three sections, first the test cases are introduced, then the results and discussion are provided.

B. Cost Minimization in Measurement Placement

1. Test Cases

Tests have been executed on both the IEEE-14 bus system and the IEEE-30 bus system. The diagrams of both networks are shown in Figures 17 and 18, and further details can be found in [56, 57]. For each network, two sets of results were obtained. First, a basic measurement placement scheme was generated to make the whole network observable. Then, more measurements were added to maintain the network observability under any contingency of the following three categories: the loss of any single measurement, any single RTU or any single branch.

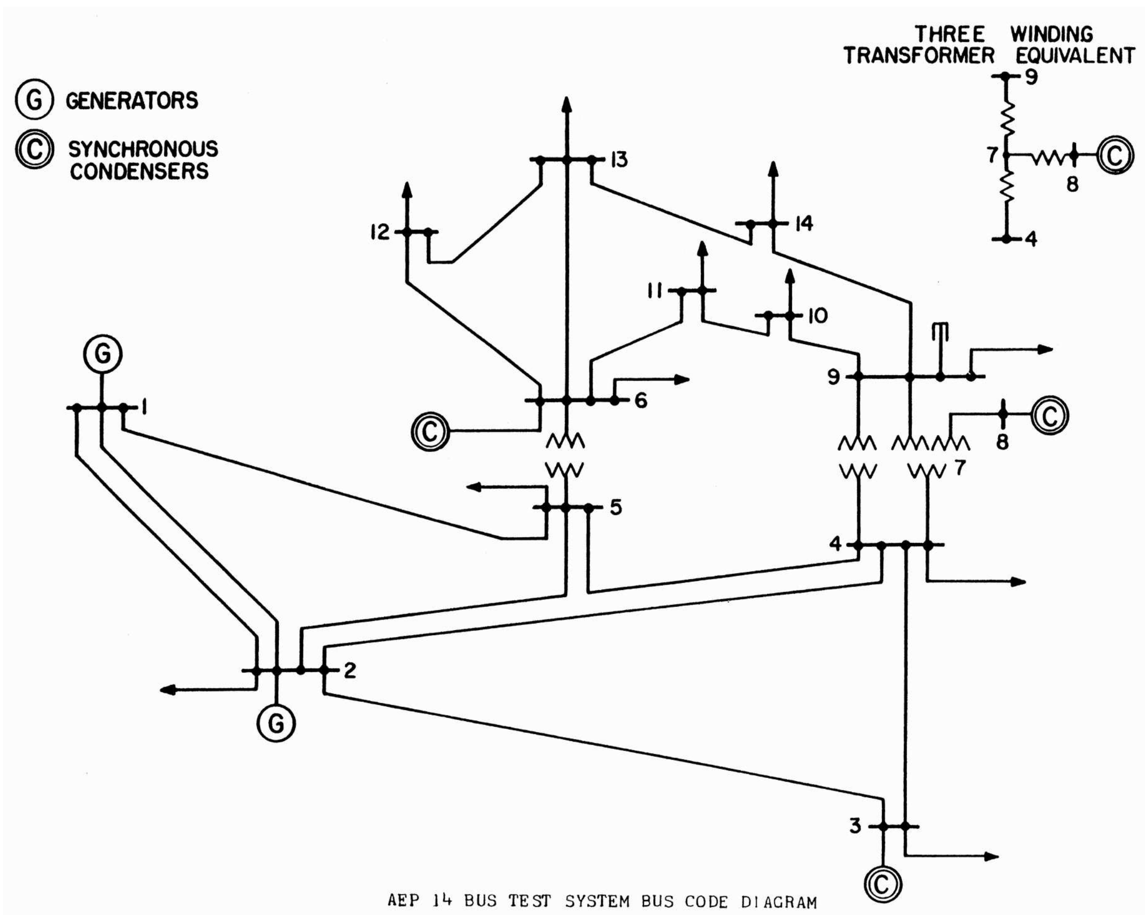

Fig. 17. IEEE-14 bus system diagram

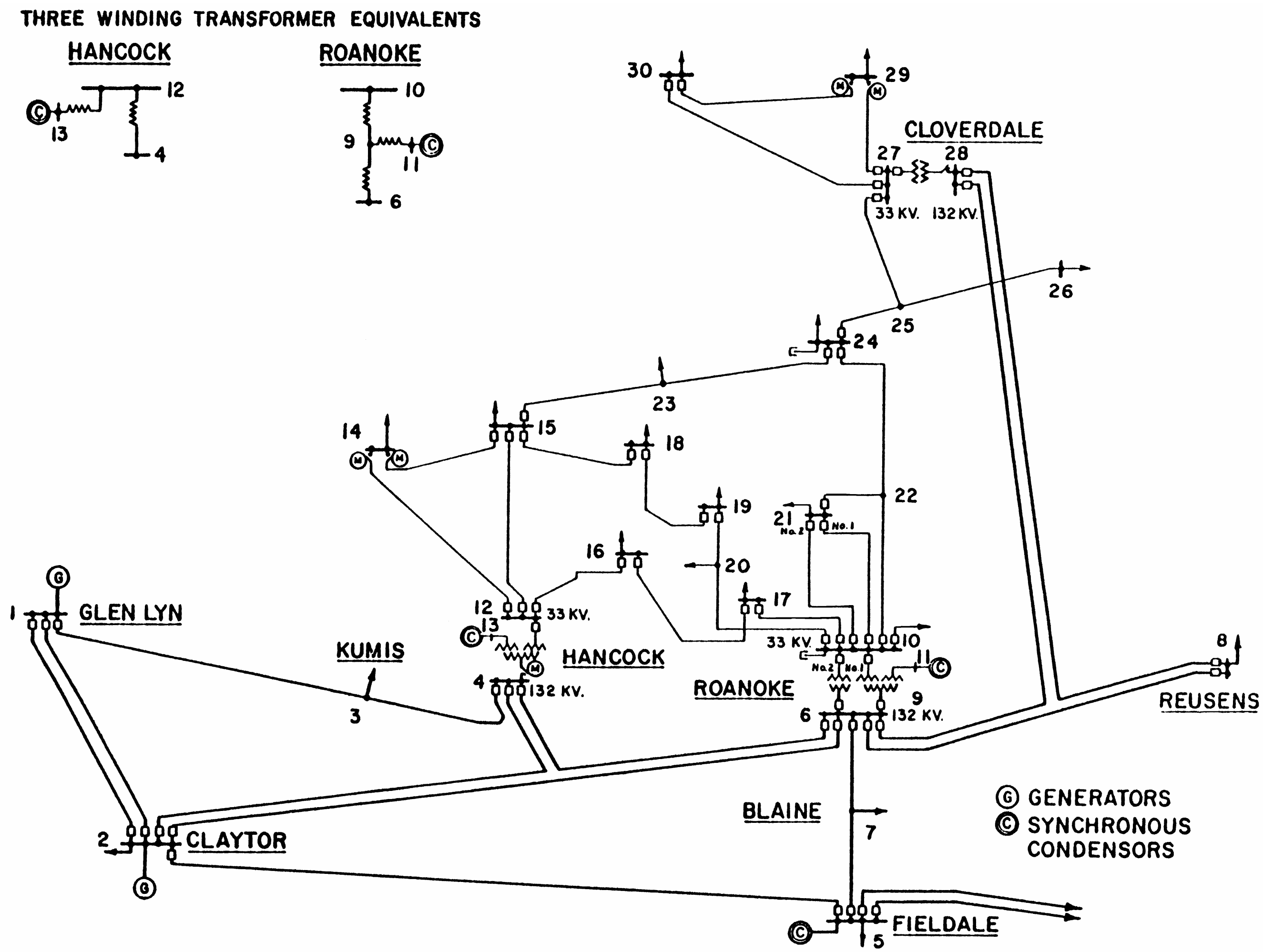

Fig. 18. IEEE-30 bus system diagram

2. Results and Discussion

The first set of measurement placement results that meets the observability constraint is listed in Table VI.

Table VI. Measurement Placement to Meet the Observability Constraint

Type	Location	
	IEEE-14	IEEE-30
Voltage magnitude measurement	8	2
Branch power flow measurement	4-2, 4-3, 4-5, 4-7, 4-9, 5-1, 5-6, 6-11, 6-12, 6-13, 9-10, 9-14, 8-7	6-2, 6-4, 6-7, 6-8, 6-9, 6-10, 6-28, 10-20, 10-17, 10-21, 10-22, 2-1, 2-5, 4-3, 4-12, 13-12, 12-14, 12-15, 12-16, 15-18, 15-23, 11-9, 27-28, 27-25, 27-29, 27-30, 25-24, 25-26, 19-20
RTU	Substation(4,7,8,9), Substation(5,6)	Substation(6,9,10,11), Substation(2), Substation(4,12,13), Substation(15), Substation(27,28), Substation(25), Substation(19)

The results were compared to the results from the test cases mentioned in [34] under the same observability constraint, as shown in Table VII. It can be seen that since the proposed method uses a heuristic method to group measurements into fewer substations, the numbers of RTUs and measurements are both greatly reduced, resulting in a more economical design.

The second set of results that meet the reliability constraints is listed in Table

Table VII. Comparison of Test Results under the Observability Constraint

Type		Number of measurements		Number of RTUs
		Voltage	Power flow	
IEEE-14	Reference [34]	1	28	5
	Proposed method	1	13	2
IEEE-30	Reference [34]	1	60	13
	Proposed method	1	29	7

VIII. The second set of results was also compared with the results from various references, as shown in Table IX. Reference [6,34,35] did not consider the contingencies of the loss of any single branch. For the purpose of comparison, the proposed method was carried out for two different situations:

1. When the loss of any single branch is not considered (at the same level of contingency requirements as in [6,34,35]);
2. When the loss of any single branch is considered (at a stricter level of contingency requirements).

It can be seen that the proposed method shows advantage in reducing the number of RTUs that are used. The method in [6] optimizes the number of measurements and therefore has advantage over the proposed method in this aspect. Considering that the price of an RTU is much higher than a transducer for a measurement, the proposed method's overall cost is still expected to be less. All the other cited methods did not consider the physical feasibility when placing measurements. For example, bus 9 in the IEEE-30 system is an internal bus of a three-winding transformer and therefore it is not practical to place measurement on bus 9. All the other methods chose to place at least two measurements on bus 9, while the proposed method did

Table VIII. Measurement Placement to Meet the Reliability Constraints

Type	Location	
	IEEE-14	IEEE-30
Voltage magnitude measurement	8	2
Branch power flow measurement	4-2, 4-3, 4-5, 4-7, 4-9, 5-1, 5-6, 6-11, 6-12, 6-13, 9-10, 9-14, 8-7	6-2, 6-4, 6-7, 6-8, 6-9, 6-10, 6-28, 10-20, 10-17, 10-21, 10-22, 2-1, 2-5, 4-3, 4-12, 13-12, 12-14, 12-15, 12-16, 15-18, 15-23, 11-9, 27-28, 27-25, 27-29, 27-30, 25-24, 25-26, 19-20
Bus injection power flow measurement	2, 5, 6, 8, 9, 13	1, 4, 5, 10, 11, 13, 15, 17, 19, 21, 23, 25, 28, 30
RTU	Substation(4,7,8,9)*, Substation(5,6)*, Substation(2), Substation(13)	Substation(2)*, Substation(6,9,10,11)*, Substation(4,12,13)*, Substation(15)*, Substation(27,28)*, Substation(5), Substation(1), Substation(17), Substation(21), Substation(23), Substation(30), Substation(25)*, Substation(19)*

*: two RTUs need to be placed in this substation.

Table IX. Comparison of Test Results under the Reliability Constraints

	Type	Number of measurements		Number of RTUs
		Voltage	Power flow	
IEEE-14	Reference [34]	1	35	8
	Proposed method (same constraints)	1	18	4
	Proposed method (more constraints)	1	19	6
IEEE-30	Reference [34]	1	68	17
	Reference [35]	1	74	18
	Reference [6]	1	30	17*
	Proposed method (same constraints)	1	40	14
	Proposed method (more constraints)	1	43	20

*: Reference [6] uses a two-stage optimization method for the measurement placement. At the end of stage I, 21 RTUs are needed. The stage II further reduces the number of RTUs to 17 by observing the results. However, no universal algorithm has been provided for stage II.

Table X. Measurement Placement

Measurement	Location
Bus voltage magnitude	4, 16
Branch power flow	29-27, 30-29, 30-27, 25-26, 12-16, 16-17, 1-3, 9-11, 14-12, 12-13, 14-15, 6-8, 28-8, 22-21, 18-19, 17-31
Bus injection power flow	25, 27, 4, 9, 10, 22, 24, 15, 12, 28, 20, 18, 2

not place any. The consideration of such an additional constraint might result in more measurements and/or RTUs to be installed for other methods.

C. Dynamic Utilization of Substation Measurements

1. Test Cases

Tests have been run on the IEEE-30 bus system. The data of the IEEE-30 bus system, including the bus-branch diagram, can be obtained from [57].

It was assumed that 31 measurements were already available to the state estimator. The types and locations of these measurements are listed in Table X.

Furthermore, the detailed breaker-and-a-half configuration was arbitrarily picked to represent the FIELDALE substation (Bus 5) in the IEEE-30 bus system, as shown in Fig. 19. Six measurements were placed in the substation, including one voltage magnitude measurement and five power flow measurements. The measurement values are listed in Table XI.

2. Results and Discussion

Using the conventional NTP, only two measurements were generated to serve the state estimator. In the bus-branch model, V_{0501} became the voltage magnitude mea-

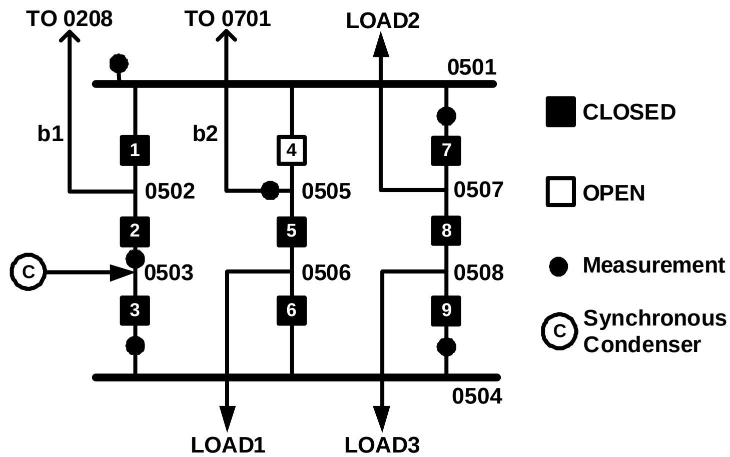

Fig. 19. Detailed substation model of the FIELDALE substation in the IEEE-30 bus system

Table XI. Measurement Data Values

Measurement	Value
V_{0501}	1.01
P_{CB2}	$45.4 - j13.0$
P_{CB3}	$45.4 + j22.8$
P_{CB7}	$34.0 + j6.9$
P_{CB9}	$-53.0 - j10.7$
P_{b2}	$14.8 - j10.6$

Table XII. Conventional NTP vs. DSUM

Measurement	NTP	DSUM
V_{bus5}	1.01, equals to V_{0501}.	1.01, equals to V_{0501}.
P_{5-2}	(Unknown)	$79.4 - j6.1$, equals to $-P_{CB2} - P_{CB7}$.
P_{5-7}	$14.8 - j10.6$, equals to P_{b2}.	$14.8 - j10.6$, equals to P_{b2}.
P_{inj5}	(Unknown)	$-94.2 + j16.7$, equals to $-P_{CB2}+P_{CB7}-2P_{CB9}-P_{b2}$.

surement of Bus 5, and P_{b2} became the branch power flow measurement of branch 5-7. The conventional NTP was also able to calculate the injection power flow of the synchronous condenser. However, the injection of Bus 5 could not be calculated since neither of the three loads' power flow could be obtained.

A topological method mentioned in Chapter II.D was used to evaluate the observability of the 30-bus network. After adding these two measurements to the system, it was found that the whole network was not totally observable.

The same measurement data were then processed by the DUSM algorithm, and four measurements were generated: the voltage magnitude measurement of Bus 5, the branch power flow measurement of branch 5-2 and 5-7, and the bus injection power flow measurement of bus 5. A comparison of the different results is shown in Table XII.

With the help of the two extra measurements that were created by DUSM, the whole network became observable, and the state estimation was then able to be executed.

Table XIII. Results under No-error Condition

CB	Power Flow	Reported Status	Verified Status	Conclusion
CB1	?	CLOSED	UNKNOWN	The CB status is unverifiable.
CB2	47.2246	CLOSED	CLOSED	The CB status is CORRECT.
CB3	50.8035	CLOSED	CLOSED	The CB status is CORRECT.
CB4	?	OPEN	UNKNOWN	The CB status is unverifiable.
CB5	?	CLOSED	UNKNOWN	The CB status is unverifiable.
CB6	14.2888	CLOSED	CLOSED	The CB status is CORRECT.
CB7	34.6931	CLOSED	CLOSED	The CB status is CORRECT.
CB8	?	CLOSED	UNKNOWN	The CB status is unverifiable.
CB9	54.0693	CLOSED	CLOSED	The CB status is CORRECT.

D. Improved Detection of Topological Errors

1. Test Cases

The test cases for the improved detection of topological errors function were from the same set-up as in section C. Six measurements were placed in substation FIELDALE (Bus 5) with the same locations and values as in Fig. 19 and Table XI.

2. Results and Discussion

The results for the CB status verification are listed in Table XIII and Table XIV.

It can be seen that in both cases, CB1, CB4, CB5 and CB8's statuses are unverifiable. This is because the topological error identification did not have enough information to calculate their power flows. Nevertheless, the error in CB6's status was successfully identified. It is worth mentioning that there was no direct mea-

Table XIV. Results When CB6 is Incorrectly Reported as OPEN

CB	Power Flow	Reported Status	Verified Status	Conclusion
CB1	?	CLOSED	UNKNOWN	The CB status is unverifiable.
CB2	47.2246	CLOSED	CLOSED	The CB status is CORRECT.
CB3	50.8035	CLOSED	CLOSED	The CB status is CORRECT.
CB4	?	OPEN	UNKNOWN	The CB status is unverifiable.
CB5	?	CLOSED	UNKNOWN	The CB status is unverifiable.
CB6	14.2888	OPEN	CLOSED	The CB status is WRONG.
CB7	34.6931	CLOSED	CLOSED	The CB status is CORRECT.
CB8	?	CLOSED	UNKNOWN	The CB status is unverifiable.
CB9	54.0693	CLOSED	CLOSED	The CB status is CORRECT.

surement of the power flow going through CB6. The topological error identification function managed to calculate CB6's power flow from CB3 and CB9's power flow, and determined that CB6 should be CLOSED.

The substation FIELDALE scenarios prove that both DUSM and the identification of topological errors can be implemented in designated substations, without the need to be introduced to all substations in the network. The performance of both functions depends on the number of measurements available in the substation(s) being analyzed. The more measurements, the better chance that DUSM can generate more useful state estimation measurement in the bus-branch model, and the more CB status errors can be detected.

E. Summary

Test results for the three proposed functions - cost minimization in measurement placement, dynamic utilization of substation measurements and improved detection of topological errors - are listed in this chapter. These test results verify the correctness of the developed functions and show their advantage over convention methods.

CHAPTER VIII

SOFTWARE IMPLEMENTATION

A. Introduction

This chapter talks about the issues with software implementation. A brief discussion of the software tools that have been used is carried out, followed by the introduction of software architecture, including the usages of functions and the input and output file formats.

B. Software Tools

1. Java

Java is an object-oriented programming language developed by Sun Microsystems in the early 1990s. The language itself borrows much syntax from C and C++ but has a simpler object model and fewer low-level facilities.

There were five primary goals in the creation of the Java language:

1. It should use the object-oriented programming methodology.
2. It should allow the same program to be executed on multiple operating systems.
3. It should contain built-in support for using computer networks.
4. It should be designed to execute code from remote sources securely.
5. It should be easy to use by selecting what was considered the good parts of other object-oriented languages.

The Java programming language was selected to develop the State Estimation Enhancement Kit (SEEK) software mainly because that it is much easier to maintain source code. Unlike other popular programming environments such as Visual C++ or Matlab, Java programming environment has great support for older program code. Those program code can often be reused directly in the new programming environment without being modified. This feature significantly reduces the workload in software maintenance and makes it easy to keep legacy systems.

Furthermore, the Java programming language has several features that facilitates the writing of codes. For example, writing help files is very easy in Java. It is very convenient to reuse existing program codes. It is also very easy to distribute software packages.

The software development platform NetBeans was used to develop the SEEK software. NetBeans is a platform for the development of Java desktop applications, which has an integrated development environment (IDE). More information about NetBeans can be found at [58].

2. XML

XML stands for the *extensible markup language*. It is a general-purpose markup language that supports a wide variety of applications. In recent years, XML has been more and more popular as a format for data exchanges among different software packages, because of its ability to contain descriptions of data fields and organize the storage of data in a tree-based structure. XML standard is maintained by World Wide Web Consortium (W3C) [59].

SEEK software uses XML as the input and output file format in most situations. A Java software package *XStream* [60] is used to expedite the handling of XML serialization of objects.

```
StateEstimator se = new StateEstimator();
se.ReadConnection( “Connectivity data file name” );// text format
// or se.ReadConnectionXML( “Connectivity data file name” );          // XML format
se.ReadCBStatus( "CB status data file name" );
// or .ReadCBStatusXML( "CB status data file name" );
se.ReadMeasurements( "Measurement data file name" );
// or se.ReadMeasurementsXML( "Measurement data file name" );
se.Update();
se.CreateCDF( "CDF file name" );
se.CreateSEMeasurements( "SE measurement data file name", false );
// false means this is a conventional topology processor
```

Fig. 20. Usage of the conventional topology processor

C. Software Architecture

1. Overview

All program codes are compacted in the SEEK package. Most software functions (except the static measurement placement function) are available in the *StateEstimator* class. This section describes the usage and software structure of the functions. The description of input and output file formats are listed in Appendix A.

2. Conventional State Estimation Functions

a. Conventional topology processor

1) Usage

Please refer to Fig. 20.

2) Input/output

Please refer to Fig. 21.

3) File format

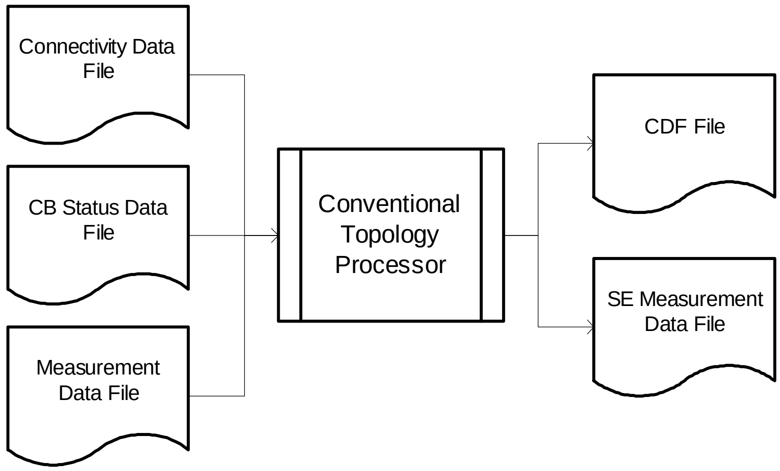

Fig. 21. The input/output of conventional topology processor

```
// After running the topology processor
boolean bObservable = se.IsObservable();
```

Fig. 22. Usage of observability analysis

Please refer to Appendix A.A-A.H. The description of the CDF file format can be found in [61].

b. Observability analysis

1) Usage

Please refer to Fig. 22.

2) Input/output

Please refer to Fig. 23.

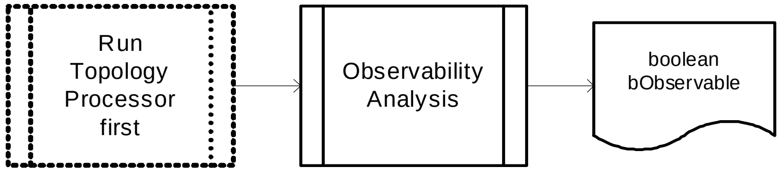

Fig. 23. The input/output of observability analysis

```
// After running the topology processor and observability analysis
if( bObservable ) se.StateEstimation( "State estimation results file name" );
```

Fig. 24. Usage of state estimation and bad data detection

c. State estimation and bad data detection

1) Usage

Please refer to Fig. 24.

2) Input/output

Please refer to Fig. 25.

3) File format

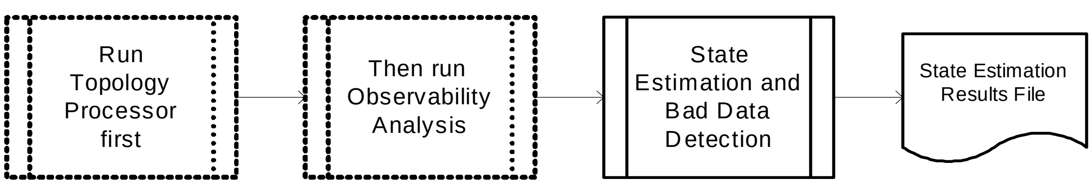

Fig. 25. The input/output of state estimation and bad data detection

```
======================================
      State Estimation Results
======================================
 Bus    V              theta
--------------------------------------
  1   1.06          0
  2   1.0431        -5.3469
  3   1.0269        -7.6044
  4   1.0194        -9.3667
  ……
============================================================
                Bad Data Detection Results
============================================================
     The numbers in brackets are normalized residuals.
    Usually a number greater than 3 indicates bad data.
------------------------------------------------------------
      Measurement      Normalized Residuals (P,Q) or (V)
------------------------------------------------------------
 Branch power flow 2-1              (0,0)
 Branch power flow 2-5              (0,0)
 Branch power flow 4-3              (0.0002,0.0008)
 Branch power flow 4-12             (0.0002,0.0008)
 Branch power flow 6-2              (0.0002,0.0008)
 ……
```

Fig. 26. An example of the state estimation results

The state estimation results file is a textual file showing the results of both the state estimation and the bad data detection. An example of such a file is shown in Fig. 26.

3. Enhanced State Estimation Functions

a. Cost minimization in measurement placement

1) Usage

Please refer to Fig. 27.

2) Input/output

Please refer to Fig. 28.

```
Place place = new Place();
place.Do("CDF file name", "Measurement placement result file");
```

Fig. 27. Usage of cost minimization in measurement placement

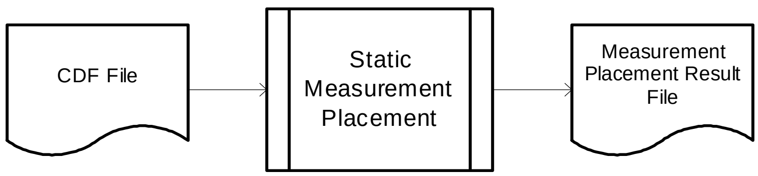

Fig. 28. The input/output of cost minimization in measurement placement

3) File format

The description of input file format (IEEE CDF) can be found in [61].

The output file is a textual file showing the results of the measurement placement. An example of such a file is shown in Fig. 29.

b. Dynamic utilization of substation measurements

1) Usage

Please refer to Fig. 30.

2) Input/output

Please refer to Fig. 31.

3) File format

Please refer to Appendix A.A-A.H.

```
======================================
 Static Measurement Placement Results
======================================
 Branch Power Flow Measurement 4-2
 Branch Power Flow Measurement 4-3
 Branch Power Flow Measurement 4-5
 Branch Power Flow Measurement 4-7
 Branch Power Flow Measurement 4-9
 Branch Power Flow Measurement 5-1
 Branch Power Flow Measurement 5-6
 Branch Power Flow Measurement 6-11
 Branch Power Flow Measurement 6-12
 Branch Power Flow Measurement 6-13
 Branch Power Flow Measurement 9-10
 Branch Power Flow Measurement 9-14
 Branch Power Flow Measurement 7-8
 Voltage Magnitude Measurement 5
```

Fig. 29. An example of measurement placement results

```
StateEstimator se = new StateEstimator();
se.ReadConnection( "Connectivity data file name" );// text format
// or se.ReadConnectionXML( "Connectivity data file name" );          // XML format
se.ReadCBStatus( "CB status data file name" );
// or .ReadCBStatusXML( "CB status data file name" );
se.ReadMeasurements( "Measurement data file name" );
// or se.ReadMeasurementsXML( "Measurement data file name" );
se.Update();
se.CreateCDF( "CDF file name" );
se.CreateSEMeasurements( "SE measurement data file name", true );
// true means this is a enhanced topology processor, featuring the dynamic utilization of substation
// measurements
```

Fig. 30. Usage of DUSM

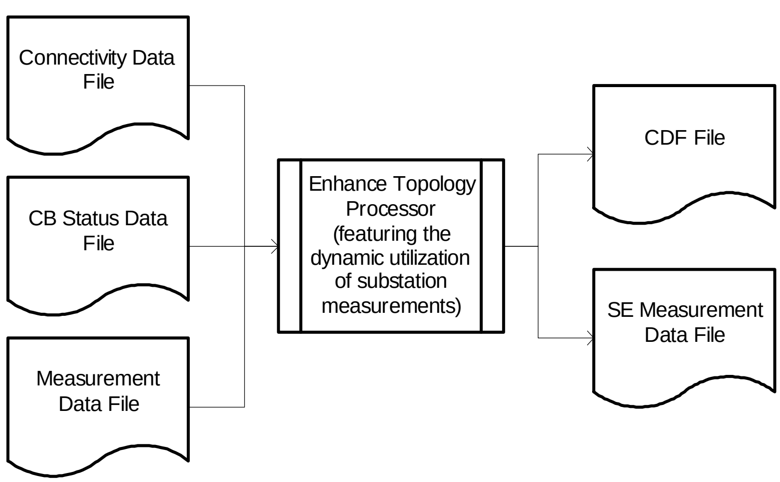

Fig. 31. The input/output of DUSM

```
// After running the topology processor
se.VefifyCBStatus( "Verification result file name" );
```

Fig. 32. Usage of improved topological error detection

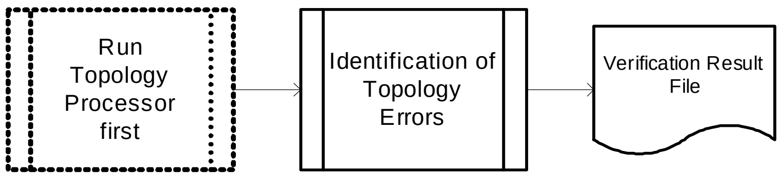

Fig. 33. The input/output of improved topological error detection

c. Improved detection of topological errors

1) Usage

Please refer to Fig. 32.

2) Input/output

Please refer to Fig. 33.

3) File format

The verification result file is a textual file showing the results of the CB status verification. An example of such a file is shown in Fig. 34.

The identification of topological errors also writes the verified CB status into a CB status XML file, the format of which is the same as Class *SEEK.CB* in Appendix A.B. An example of such a file is shown in Fig. 35.

```
==========================================================================================================
                                    CB Status Verification Results
==========================================================================================================
CB    Power Flow      Reported Status Verified Status   Conclusion
CB1     ?               UNKNOWN         UNKNOWN         The CB status is unverifiable.
CB2     47.2246         UNKNOWN         CLOSED          The CB status is verified to be CLOSED.
CB3     0               CLOSED          OPEN            The CB status is WRONG.
CB6     14.2888         UNKNOWN         CLOSED          The CB status is verified to be CLOSED.
......
```

Fig. 34. An example of CB status verification results


```
<list>
  <SEEK.CB>
    <sName>CB1101</sName>
    <sFrom>1101</sFrom>
    <sTo>1102</sTo>
    <nFromBus>10</nFromBus>
    <nToBus>10</nToBus>
    <nStatus>1</nStatus>
    <dFlowValues>
      <double>0.0</double>
      <double>-0.23995</double>
    </dFlowValues>
    <nVerifiedStatus>1</nVerifiedStatus>
    <sVerification>The CB status is CORRECT.</sVerification>
  </SEEK.CB>
  ….
</list>
```


Fig. 35. CB status verification results in XML format

D. Summary

This chapter talks about the software implementation aspect of the newly developed functions. The whole software package was developed in Java, with XML format input/output support. The software architecture is shown in this chapter, followed by the introduction of function usages and input/output file formats.

CHAPTER IX

APPLICABILITY IN PRACTICE

A. Introduction

This chapter will talk about the issues associated with the implementation of the proposed methods in the real world. First, the benefits will be discussed for each of the three methods. Then, potential implementation limitations and difficulties will be mentioned.

B. Benefits

1. Cost Minimization in Measurement Placement

The cost minimization in measurement placement can be very helpful in planning power network measurement systems, especially under situation where there is a tight budget. It is a completely computer-based algorithm and its performance does not compromise with the increase of system size or complexity.

2. Dynamic Utilization of Substation Measurements

The DUSM algorithm uses the following implicit assumptions:

1. It assumes that the Kirchhoff's current law is applicable, which requires that there is no unknown ground fault or ground leakage current existing in the substation. This is usually true, since firstly, the possibility of ground faults in a substation is low; secondly, in case of a bus ground fault, the bus protection will trip all CBs that are connected to the bus and clear the leakage current.

2. The open CBs are excluded from the topological matrix and the power flows

through them are assumed to be zero. This requires that the CB statuses are correctly reported. If the CB status measurements are not accurate enough, the open CBs should still be included in the topological matrix and the power flow through them should be regarded as unknown.

The DUSM algorithm can be implemented as a supplementary function to the substation automation system (SAS), or to the EMS in the control center.

The advantages of implementing DUSM in substations are:

1. More measurements are available in substations than in the control center. In recent digital substations, besides the measurements that are gathered by RTUs, many intelligent electronic devices (IEDs) also record and monitor the status of the substation on-line. Many measurement data can be obtained from the recording of these devices [1].

2. Because of the independent storage of substation topological information, DUSM can be implemented in any number of substations in the system. This adds to the flexibility of implementation. A few substations may be picked up and the effectiveness of the new algorithm may be tested without the need for upgrading the existing EMS software in the control center or SAS software in other substations.

On the other hand, the advantage of implementation in the control center is that the full potential of dynamically creating new measurements for the state estimation purpose can be obtained. The EMS in control center has the access to the topological information from all substations. The installation of the new algorithm will enable the new measurements to be calculated from all the measurements that are transmitted to the control center.

3. Improved Detection of Topological Errors

The improved detection of topological errors is an extension of the function of DUSM and therefore can be implemented together with DUSM without bring much overhead. It can also be used as a supplementary function for DUSM to verify the correctness of topological information in substations.

Similar to DUSM, this function can also be installed in SAS level or EMS level.

C. Potential Implementation Limitations and Difficulties

The limitations of cost minimization in measurement placement are:

1. The placement of measurements are implemented at the bus-branch model level. How to place physical metering devices in substations is not proposed. In the planning stage, the users still need to allocate the metering devices manually according to the substation configurations.

2. The second step of the algorithm to meet the contingency requirements might cost long computation time with the increase of system size.

The limitations of DUSM are:

1. DUSM uses available substation measurements to calculate un-measured values, therefore any bad data contained in the measurement set will be propagated into other measurement variables. Because of this, the accuracy of state estimation might be compromised. Once again, the purpose of DUSM is to find more state estimation measurements for the purpose of recovering the network observability, therefore it should be used in networks where the number of measurements is limited and the network observability is a concern. DUSM should not be used as a method to improve the accuracy of state estimation.

2. DUSM assumes the network topology is correctly represented. Error in CB status will result in wrong calculation results of state estimation measurements. Therefore, other topological error detection methods should be applied before DUSM to guarantee the accuracy of results.

The limitations of improved detection of topological errors is: since it is a rule-based method based on topology processing, it cannot integrate with the traditional state estimator seamlessly, not like those existing methods which, by modifying the state estimator itself, are able to detect topological errors and bad analog data at the same time.

D. Summary

This chapter summarizes the issues associated with the implementation of the proposed methods in the real world. Since the applicability of the methods has already been considered during the design, the proposed methods are not difficult to be implemented. However, aspects that might affect the effectiveness of the proposed methods also exist and are mentioned in this chapter.

CHAPTER X

CONCLUSIONS

A. Introduction

This dissertation introduces three topics related to the power system state estimation on which new algorithms are developed:

- How to minimize the number of measuring devices and installation cost in the network, while the system observability requirements are still met?
- How to more efficiently use those available measurements in substations that are often neglected in the creation of bus-branch model of the whole system?
- How to verify CB status without modifying the state estimator, even though the CB power flow is not directly measured?

The algorithms were developed using Java, with the choice of either plain text or XML as the input/output file format. Test results show encouraging enhancement of the developed algorithms.

B. Summary of Contributions

An innovative method for the placement optimization of power system measurement is developed. The goal of the method is to minimize the number of necessary measurements and required RTUs, subject to the system observability requirements. Three types of measurements are considered: bus voltage magnitude measurements, branch power flow measurements and bus injection power flow measurements. A fast algorithm for building up the spanning tree in the observability analysis is developed and applied for the measurement placing process. The algorithm consists of two steps.

First, the branch power flow and bus voltage magnitude measurements are placed. The spanning tree of the network is selected by choosing the branches that are connected to the buses with large numbers of incident branches. Once the spanning tree is decided, branch power flow measurements are placed on its branches and installed into as few substations as possible. A voltage measurement is also placed in a substation that already has at least one branch measurement installed. Second, the bus injection power flow measurements are placed in selected substations to backup the branch measurements and add up to the robustness of the measurement placement scheme against the loss of observability.

In a power system state estimator, an NTP determines the CB status in real-time to obtain electrical network topology. In a conventional NTP, many substation measurements are simply discarded because their positions in the simplified bus-branch network model are lost. These measurements cannot be used in the network observability analysis and when some of the used measurements are lost, an estimate of system states may not be obtained. This dissertation proposes an innovative method to utilize these redundant measurements. The new method uses a numerical matrix to represent the physical connectivity of substation devices, and then dynamically searches for solutions to calculate branch and bus injection power flow measurement data using the linear combination of the available substation measurement data. Test cases verify that the proposed method is very effective in making the network observable, without the need to install new measurement devices.

Topological errors in power system network will result in incorrect estimate of system states. Most previous methods to detect topological errors require the modification of state estimator to include the state variables that relate to CB status. This dissertation presents an improved topological error detection algorithm using the idea of improved topology processing. The rule-based method is used and no change is introduced to the state estimator. The proposed topological error detection is an extension of the dynamic utilization of substation measurements function and some CB's status can still be verified even when power flow measurement is not available.

C. Future Work

In the future, current research work can seek improvement in the following directions:

1. A mathematical analysis regarding the impact of DUSM towards the accuracy of state estimation should be carried out. It can be assumed that the measurement data generated by DUSM are easier to be affected by bad data than additional physical measurements. However, how to quantify the difference remains an unsolved task.

2. An automatic measurement placement scheme at the substation level should be developed in the future. The input of the scheme is the result of the proposed measurement placement algorithm, and the output is a placement plan for physical devices in substation. This will greatly increase the efficiency of testing all three proposed methods.

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APPENDIX A

INPUT AND OUTPUT FILE FORMATS

A. Connectivity Data File (Text Format)

1. Circuit Breakers

Format:

```
#BEGIN CB_DATA
CB name,from node,to node
CB name,from node,to node
CB name,from node,to node
...
#END
```

Example:

```
#BEGIN CB\_DATA
CB0101,0101,0102
CB0102,0102,0103
CB0103,0103,0104
#END
```

2. Nodal Injections

Format:

```
#BEGIN NODE_DATA
node,type,data1,data2,maxQ,minQ,G,B
node,type,data1,data2,maxQ,minQ,G,B
node,type,data1,data2,maxQ,minQ,G,B
...
#END

where:  type can be 0(PQ), 2(PV), or 3(Slack).
        For type 3 nodes: data1 = V, data2 = angle.
        For type 2 nodes: data1 = P, data2 = V.
        For type 0 nodes: data1 = P, data2 = Q.
```

Example:

```
#BEGIN NODE_DATA
0102,G3,1.06,0,0,0,0,0
0206,G2,40,1.043,50,-40,0,0
0209,L0,21.7,12.7,0,0,0,0
0302,L0,2.4,1.2,0,0,0,0
0404,L0,7.6,1.6,0,0,0,0
#END
```

3. Branches

Format:

```
#BEGIN BRANCH\_DATA
from node,to node,R,X,B<,ratio(for transformers)>
from node,to node,R,X,B<,ratio(for transformers)>
from node,to node,R,X,B<,ratio(for transformers)>
...
#END

where:  ratio is for transformer branches only.
```

Example:

```
#BEGIN NODE_DATA
0102,G3,1.06,0,0,0,0,0
0206,G2,40,1.043,50,-40,0,0
0209,L0,21.7,12.7,0,0,0,0
0302,L0,2.4,1.2,0,0,0,0
0404,L0,7.6,1.6,0,0,0,0
#END
```

B. Connectivity Data File (XML Format)

Format:

Class SEEK.CB

```
  sName: CB name, String
  sFrom: from node name, String
  sTo: to node name, String
  nFromBus: from bus number, int, default value -1
  nToBus: to bus number, int, default value -1
  nStatus: CB status, 0-OPEN, 1-CLOSED, 2-UNKNOWN, default value 2
  dFlowValues: P and Q values, double, default value NaN
  nVerifiedStatus: verified CB status, 0-OPEN, 1-CLOSED, 2-UNKNOWN, default
                   value 2
  sVerification: verification result, String, default value "The CB status
                 is unverifiable."

  The fields nFromBus, nToBus, nStatus, dFlowValues, nVerifiedStatus,
  sVerification will be updated by the program. For compatibility purpose,
  they are required to appear in the input file. Users can put any values in
  these fields. It will not affect the results.
```

Class SEEK.Branch

```
  sName: branch name, String
  sFrom: from node name, String
  sTo: to node name, String
  nFromBus: from bus number, int, default value -1
  nToBus: to bus number, int, default value -1
  dR: R of the branch, double
  dX: X of the branch, double
```

```
dB: B of the branch, double
dRatio: transformer ratio, double. 0 if not a transformer.

The fields sName, nFromBus, nToBus will be updated by the program. For
compatibility purpose, they are required to appear in the input file.
Users can put any values in these fields. It will not affect the results.
```

Class SEEK.Injection

```
sName: injection name, String
sNode: node where the injection is on, String
nBus: bus number of where the injection is on, int
sType: injection type, String, see explanations in the text format
       Connectivity Data File
dData: data fields, double, see explanations in the text format
       Connectivity Data File
dMinQ: minimum Q of the injection device, double
dMaxQ: maximum Q of the injection device, double
dG: G of the injection device, double
dB: B of the injection device, double

The fields sName, nBus will be updated by the program. For compatibility
purpose, they are required to appear in the input file. Users can put any
values in these fields. It will not affect the results.
```

Example:

```
<SEEK.Connection>
  <cbs>
    <SEEK.CB>
      <sName>CB0101</sName>
      <sFrom>0101</sFrom>
      <sTo>0102</sTo>
      <nFromBus>-1</nFromBus>
      <nToBus>-1</nToBus>
      <nStatus>2</nStatus>
      <dFlowValues>
        <double>NaN</double>
        <double>NaN</double>
      </dFlowValues>
      <nVerifiedStatus>2</nVerifiedStatus>
      <sVerification>The CB status is unverifiable.</sVerification>
    </SEEK.CB>
    ...
  </cbs>
  <branches>
    <SEEK.Branch>
      <sName>b_0103_0203</sName>
      <sFrom>0103</sFrom>
      <sTo>0203</sTo>
      <nFromBus>-1</nFromBus>
      <nToBus>-1</nToBus>
      <dR>0.0384</dR>
      <dX>0.115</dX>
      <dB>0.0264</dB>
      <dRatio>0.0</dRatio>
    </SEEK.Branch>
    ...
  </branches>
  <injections>
    <SEEK.Injection>
```

```
      <sName>I_0102</sName>
      <sNode>0102</sNode>
      <nBus>-1</nBus>
      <sType>G3</sType>
      <dData>
        <double>1.06</double>
        <double>0.0</double>
      </dData>
      <dMinQ>0.0</dMinQ>
      <dMaxQ>0.0</dMaxQ>
      <dG>0.0</dG>
      <dB>0.0</dB>
    </SEEK.Injection>
    ...
  </injections>
</SEEK.Connection>
```

C. CB Status Data File (Text Format)

Format:

```
CB name,status(0-open,1-closed,2-unknown)
CB name,status(0-open,1-closed,2-unknown)
CB name,status(0-open,1-closed,2-unknown)
...
```

Example:

```
CB0101,1
CB0102,1
CB0103,0
CB0104,1
```

D. CB Status Data File (XML Format)

Format:

Class SEEK.CBStat

```
  sName: CB name, String
  nStatus: CB status, 0-OPEN, 1-CLOSED, 2-UNKNOWN
```

Example:

```
<SEEK.CBStatus>
  <m__cbstats>
    <SEEK.CBStat>
      <sName>CB0101</sName>
      <nStatus>1</nStatus>
    </SEEK.CBStat>
    ...
  </m__cbstats>
</SEEK.CBStatus>
```

E. Measurement Data File (Text Format)

Format:

```
location, value1, value2, SD1, SD2
location, value1, value2, SD1, SD2
location, value1, value2, SD1, SD2
...

where:
  For CB power flow measurements: location = [CB name]. The direction of the
  measurement is the same as the CB.

  For injection power flow measurements: location = \P[node]. The direction of
  measurement is always going into the node.

  For voltage measurements: location = \V[node].

  For power flow measurements, value1=P, value2=Q, SD1=P's standard deviation,
  SD2=Q's standard deviation.

  For voltage measurements, value1=voltage, value2=0, SD1=voltage's standard
  deviation, SD2=0.
```

Example:

```
\P0404,-0.07600,-0.01600,0.001,0.001
\P0604,0.58513,-0.02625,0.001,0.001
\P0605,-0.38157,0.01965,0.001,0.001
\P0606,-0.29636,0.03263,0.001,0.001
\P0609,-0.19049,-0.01369,0.001,0.001
\P0608,-0.289,0.03881,0.001,0.001
CB2,45.4,-13.0,0.01,0.01
CB3,45.4,22.8,0.01,0.01
CB7,34.0,6.9,0.01,0.01
\V0201,1.0431,0,0.001,0
```

F. Measurement Data File (XML Format)

Format:

```
Class SEEK.Measurement

  sName: measurement name, String, equals to "M_"+location. See explanation in
         the text format Measurement Data File.
  sLocation: node where the measurement is installed, String
  sType: measurement type, String, can be "voltage", "injection" or "CB flow".
  sNode: the corresponding node names, String, default value ""
  nBuses: the corresponding bus numbers, int, default value -1
  dValues: measurement values, double
  dStdDev: the standard deviations of the measurement value, double

  The fields sNodes, nBuses will be updated by the program. For compatibility
  purpose, they are required to appear in the input file. Users can put any
  values in these fields. It will not affect the results.
```

Example:

```
<list>
  <SEEK.Measurement>
    <sName>M_\V0201</sName>
    <sLocation>0201</sLocation>
    <sType>voltage</sType>
    <sNodes>
      <string></string>
      <string></string>
    </sNodes>
    <nBuses>
      <int>-1</int>
      <int>-1</int>
    </nBuses>
    <dValues>
      <double>1.0431</double>
      <double>0.0</double>
    </dValues>
    <dStdDev>
      <double>0.0010</double>
      <double>0.0</double>
    </dStdDev>
  </SEEK.Measurement>
  ...
</list>
```

G. SE Measurement Data File (Text Format)

Format:

```
VOLTAGE MEASUREMENTS FOLLOWS
Bus=[Bus#]    Values=[Voltage]
Bus=[Bus#]    Values=[Voltage]
...
INJECTION MEASUREMENTS FOLLOWS
Bus=[Bus#]    Values=(P,Q)
Bus=[Bus#]    Values=(P,Q)
...
BRANCH MEASUREMENTS FOLLOWS
Branch=[from bus]-[to bus]    Values=(P,Q)
Branch=[from bus]-[to bus]    Values=(P,Q)
...
```

Example:

```
VOLTAGE MEASUREMENTS FOLLOWS
Bus=2    Values=1.01
INJECTION MEASUREMENTS FOLLOWS
Bus=2    Values=(-48.8,3.7)
BRANCH MEASUREMENTS FOLLOWS
Branch=1-2    Values=(0,0)
Branch=2-1    Values=(34,6.9)
Branch=2-3    Values=(14.8,-10.6)
Branch=3-2    Values=(0,0)
```

H. SE Measurement Data File (XML Format)

Format:

Class SEEK.CBStat

```
nBus: bus number where measurement is located, int
dValues: P and Q measurement values, double
dStdDev: standard deviation of P and Q measurement values, double
```

Class SEEK.SEBranch

```
nBuses: the from and to bus, int
dValues: P and Q measurement values, double
dStdDev: standard deviation of P and Q measurement values, double
```

Class SEEK.SEVoltage

```
nBus: bus number where measurement is located, int
dValue: V value, double
dStdDev: standard deviation of V, double
```

Example:


```
<SEEK.SEMeasurement>
  <m__injections>
    <SEEK.SEInjection>
      <nBus>3</nBus>
      <dValues>
        <double>-0.076</double>
        <double>-0.016</double>
      </dValues>
      <dStdDev>
        <double>0.0010</double>
        <double>0.0010</double>
      </dStdDev>
    </SEEK.SEInjection>
    ...
  </m__injections>
  <m__branches>
    <SEEK.SEBranch>
      <nBuses>
        <int>5</int>
        <int>9</int>
      </nBuses>
      <dValues>
        <double>-0.1667</double>
        <double>-0.00741</double>
      </dValues>
      <dStdDev>
        <double>0.0010</double>
        <double>0.0010</double>
      </dStdDev>
    </SEEK.SEBranch>
    ...
  </m__branches>
  <m__voltages>
    <SEEK.SEVoltage>
```

```
      <nBus>1</nBus>
      <dValue>1.0431</dValue>
      <dStdDev>0.0010</dStdDev>
    </SEEK.SEVoltage>
    ...
  </m__voltages>
</SEEK.SEMeasurement>
```

APPENDIX B

SUBSTATION DIAGRAMS (IEEE 30-BUS SYSTEM)

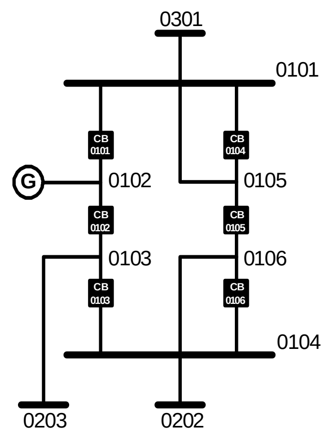

Fig. 36. Bus 1

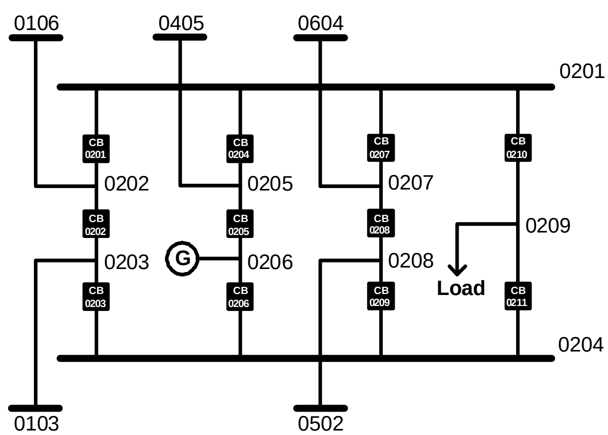

Fig. 37. Bus 2

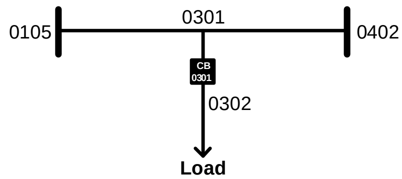

Fig. 38. Bus 3

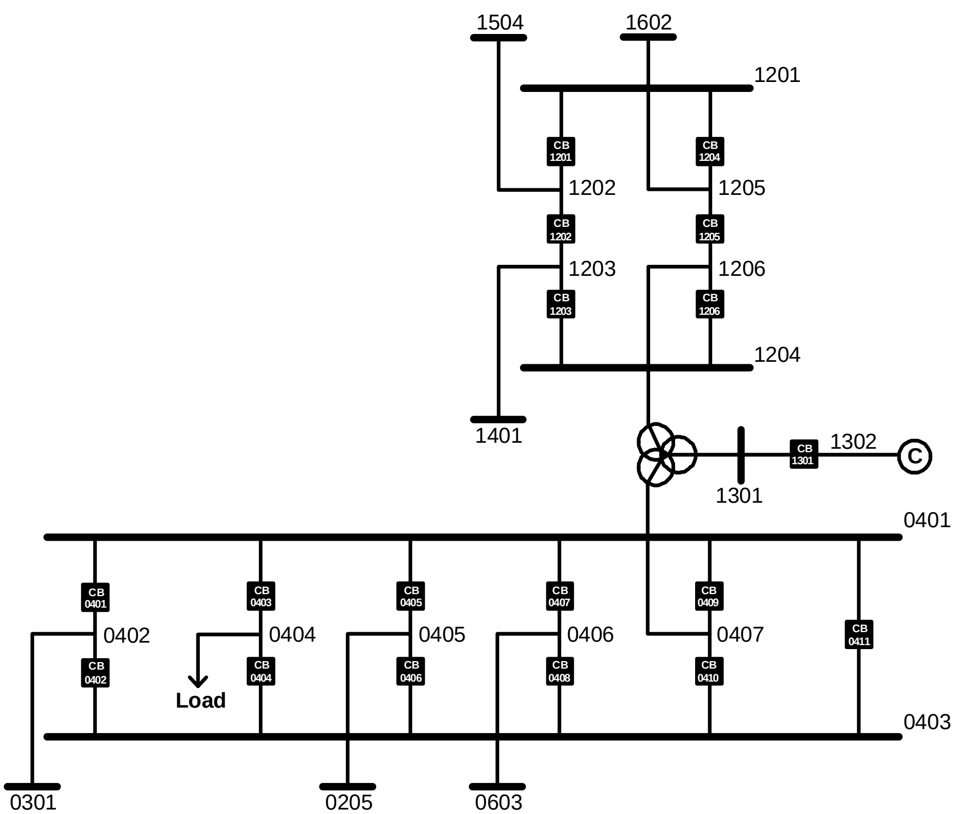

Fig. 39. Bus 4, 12, 13

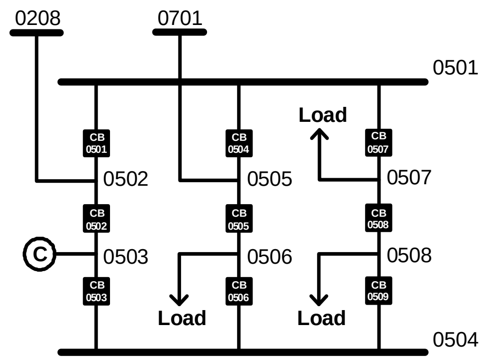

Fig. 40. Bus 5

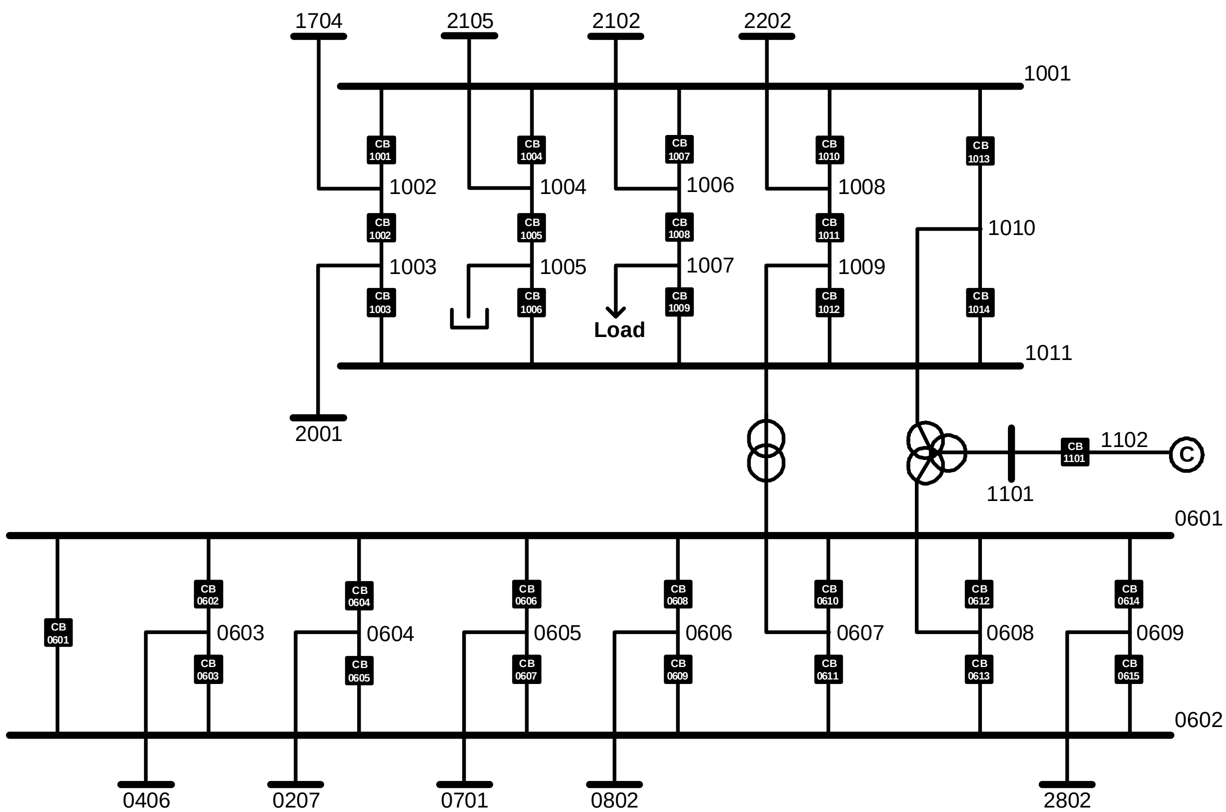

Fig. 41. Bus 6, 9, 10, 11

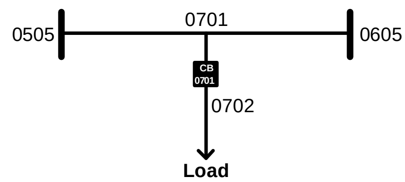

Fig. 42. Bus 7

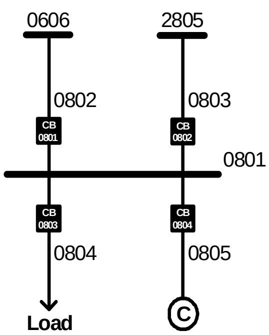

Fig. 43. Bus 8

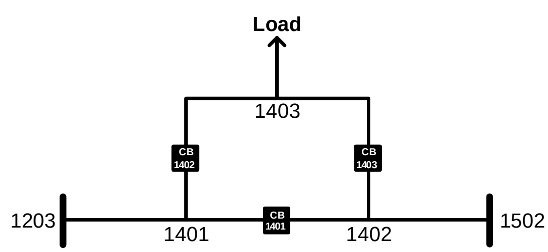

Fig. 44. Bus 14

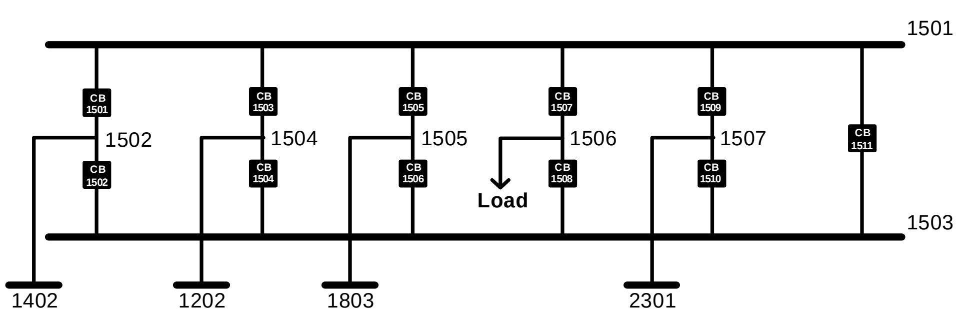

Fig. 45. Bus 15

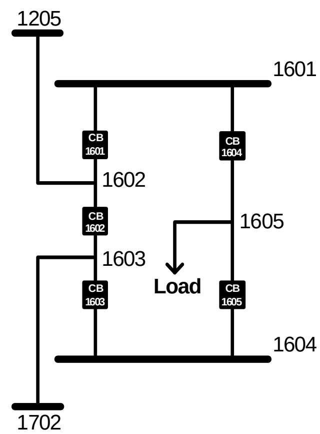

Fig. 46. Bus 16

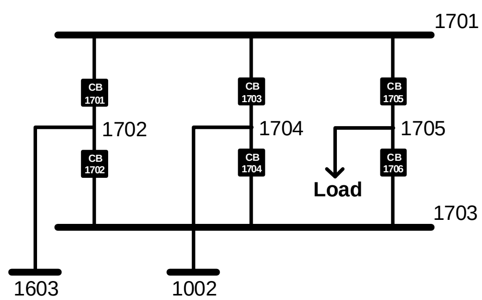

Fig. 47. Bus 17

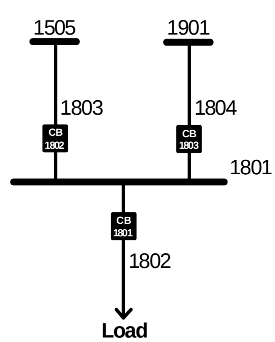

Fig. 48. Bus 18

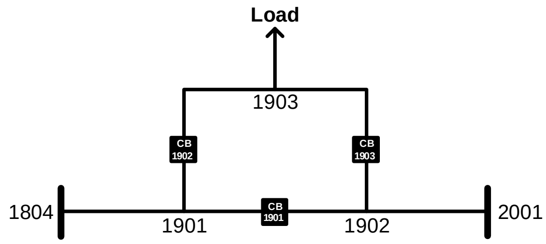

Fig. 49. Bus 19

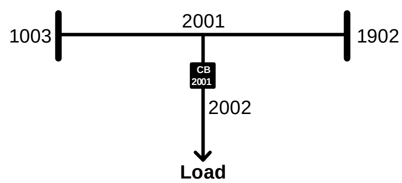

Fig. 50. Bus 20

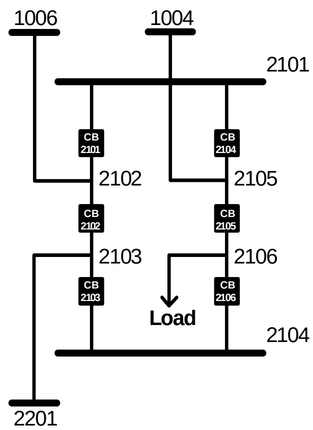

Fig. 51. Bus 21

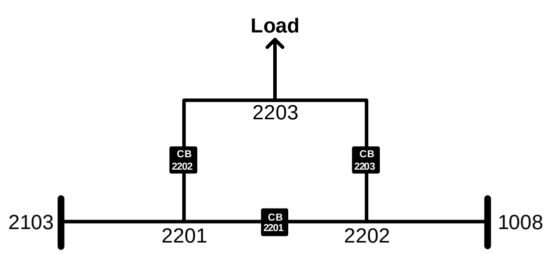

Fig. 52. Bus 22

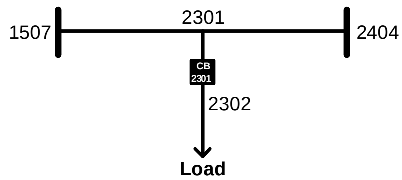

Fig. 53. Bus 23

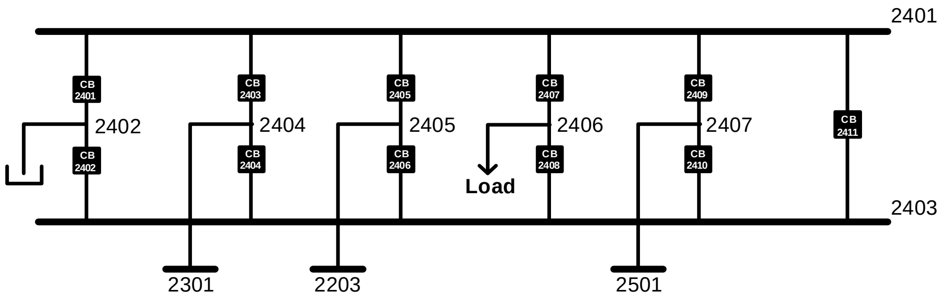

Fig. 54. Bus 24

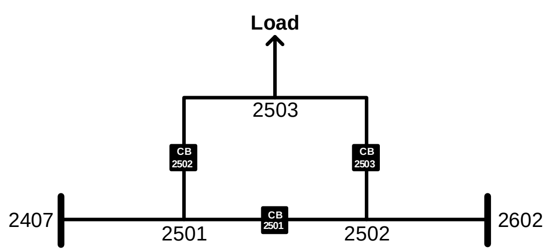

Fig. 55. Bus 25

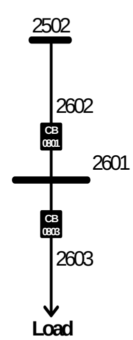

Fig. 56. Bus 26

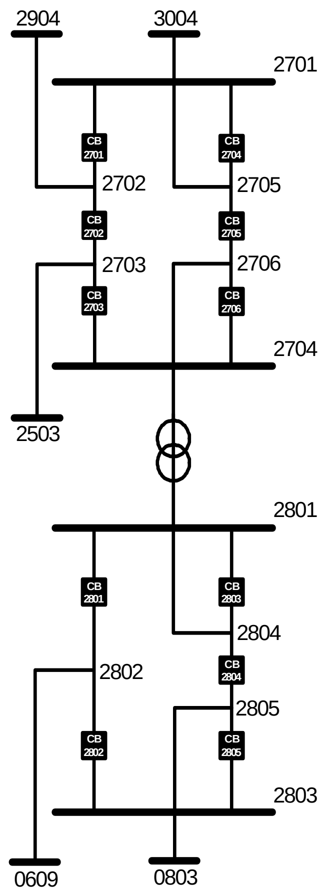

Fig. 57. Bus 27, 28

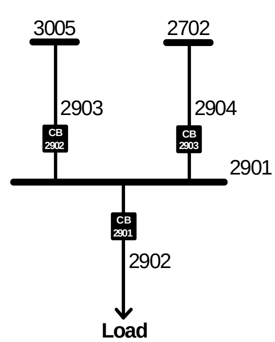

Fig. 58. Bus 29

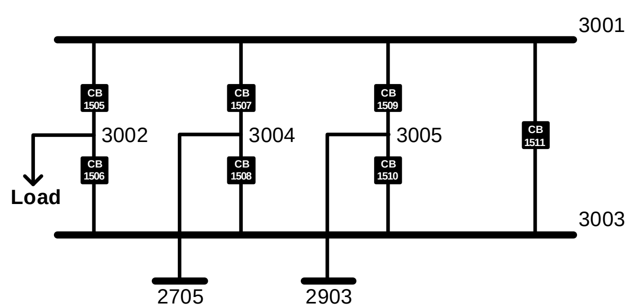
3001
CB 1505
CB 1507
CB 1509
3002
3004
3005
CB 1511
CB 1506
CB 1508
CB 1510
Load
3003
2705
2903

Fig. 59. Bus 30

VITA

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